State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-088-17a

UTAH AIR QUALITY BOARD MEETING
FINAL AGENDA

Wednesday, January 3, 2018 - 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

I. Call-to-Order

II. Date of the Next Air Quality Board Meeting: February 7, 2018

III. Approval of the Minutes for December 6, 2017, Board Meeting.

IV. Final Adoption: Change in Proposed R307-150. Emission Inventories; R307-401. Permit: New and Modified Sources; R307-504. Oil and Gas Industry: Tank Truck Loading; R307-506. Oil and Gas Industry: Storage Vessel; R307-507. Oil and Gas Industry: Dehydrators; R307-508. Oil and Gas Industry: VOC Control Devices; R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-510. Oil and Gas Industry: Natural Gas Engine Requirements; and New Rule R307-505. Oil and Gas Industry: Registration Requirements. Presented by Thomas Gunter.

V. Propose for Public Comment: Amend R307-101-3. Version of Code of Federal Regulations Incorporated by Reference. Presented by Thomas Gunter.

VI. Propose for Public Comment: R307-210. Standards of Performance for New Stationary Sources. Presented by Thomas Gunter.

VII. Propose for Public Comment: Amend R307-214. National Emission Standards for Hazardous Air Pollutants. Presented by Thomas Gunter.

VIII. Informational Items.
- A. Ozone Designations Update. Presented by Jay Baker.
- B. Air Toxics. Presented by Robert Ford.
- C. Compliance. Presented by Jay Morris and Harold Burge.
- D. Monitoring. Presented by Bo Call.
- E. Other Items to be Brought Before the Board.
- F. Board Meeting Follow-up Items.

In compliance with the Americans with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Larene Wyss, Office of Human Resources at (801) 536-4281, TDD (801) 536-4284 or by email at lwyss@utah.gov.

ITEM 3

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UTAH AIR QUALITY BOARD MEETING
December 6, 2017 – 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

DRAFT MINUTES

I. Call-to-Order

Michael Smith called the meeting to order at 1:30 p.m.

Board members present: Michael Smith, Erin Mendenhall, Kevin Cromar, Mitra Kashanchi, Cassady Kristensen, Randal Martin, Alan Matheson, Arnold Reitze, William Stringer

Executive Secretary: Bryce Bird

Mitra Kashanchi was introduced as a new Board member who replaces Karma Thomson. Ms. Kashanchi represents the fuels industry as Chevron's Utah refinery manager.

II. Date of the Next Air Quality Board Meeting: January 3, 2018

III. Approval of the Minutes for October 4, 2017, Board Meeting.

A correction was made on page 7 where it has marginal attainment. It should actually be marginal nonattainment.

- Arnold Reitze moved to approve the minutes as corrected. Erin Mendenhall seconded. The Board approved unanimously.

IV. Final Adoption: Amend R307-403. Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas. Presented by Mat Carlile.

Mat Carlile, Environmental Planning Consultant at DAQ, stated that EPA entered into a consent decree on June 2, 2016, which required them to approve, disapprove, or conditionally approve certain state implementation plan (SIP) submissions from states to address specific requirements for the 2006 $PM_{2.5}$ national ambient air quality standards (NAAQS). R307-403 was one of these submissions. EPA determined that there were potential deficiencies in R307-403. In response to EPA, the DAQ sent a letter to EPA committing to revise portions of R307-403 no later than December 8, 2017. The amendments today fulfill those commitments. On September 6, 2017, the

Board proposed amendments to R307-403. A public comment period was held from October 1 to October 31, 2017. No comments were received and no hearing was requested. However, comments made at the September 6, 2017, Board meeting did not get incorporated into the document that was released for public comment. The suggested changes were not substantive and have been incorporated into the proposed rule for adoption. Staff recommends that the Board adopt R307-403 as amended.

Mr. Martin stated that there is a problem where it states in R307-403-1(c) that ammonia is listed as not being a precursor to $PM_{2.5}$ in the Logan, Salt Lake, and Provo nonattainment areas when scientifice research shows that language is not defensible in those air sheds. There was also discussion about the possibility of a change in language and what are the administrative impacts of making any changes at this point.

Staff explained that this rulemaking action is part of the consent decree that EPA entered into to satisfy several moderate area SIP obligations from Utah and other states. SIPs have different elements, one of which is the nonattainment new source review (NNSR) requirements. Utah has submitted the SIPs for these areas and since then a new PM implementation rule came out which requires a precursor analysis as pertaining to NNSR. DAQ is trying to supplement each of the moderate area SIPs with the analysis so that EPA can ultimately take action. The Logan analysis is complete and concludes that the area is rich in ammonia and therefore it is appropriate to exempt ammonia as a precursor. DAQ worked out with EPA over the last year to satisfy EPA's consent agreement and DAQ has committed to revising its NNSR rules by the end of this week as per EPA's suggested corrections. Initially, there was language in a draft amendement of the rule stating that upon a demonstration ammonia would not be a precursor. EPA found this objectionable. The rules today include language for not just the Logan area, which is supported by the demonstration, but also the other two areas with the understanding that these will be revisited in the work for the serious area SIPs for the Salt Lake and Provo areas. From an administrative standpoint, if changes were made to the language as suggested today staff would not have time to fix other inconsistencies in the rule because the modeling has not been done for the Salt Lake and Provo areas. Staff indicates there are two options before the Board. The Board could go forward with the rule as is with the understanding that the rule will be revisited at a later date which would address the issue of ammonia as a precursor; or the Board could table the rule and allow it to lapse and again deal with it at a later date.

Staff also responded to the question asking if there are any sources of ammonia in these areas based on the emissions inventory. There are two sources in the Salt Lake area, one source in Utah County, and no sources in Logan for sources over 70 tons per year. Staff also explained that in R307-403-5(2) where it reads that "for the offset determinations, PM10, sulfur dioxide, and oxides of nitrogen shall be considered on an equal basis" is specific to the PM_{10} nonattainment areas and those pollutants are looked at on a one-for-one ratio. In R307-403-5(4)(e), where it states that offsets may not be traded between pollutants, is for $PM_{2.5}$ nonattainment areas which is specific to major source permitting.

- Kevin Cromar moved that the Board allow R307-403 to lapse and not submit for final adoption. Randal Martin seconded. The Board approved the motion with seven in favor (E. Mendenhall, K. Cromar, M. Kashanchi, C. Kristensen, R. Martin, A. Reitze, W. Stringer) and one against (M. Smith).

V. Propose for Public Comment: Amend R307-350. Miscellaneous Metal Parts and Products Coatings; R307-353. Plastic Parts Coatings; and R307-355. Aerospace Manufacture and Rework Facilities. Presented by Mat Carlile.

Mat Carlile, Environmental Planning Consultant at DAQ, stated that on October 4, 2017, the Board directed staff to bring back proposed amendments to R307-350, R307-353, and R307-355. Some Board members expressed concerns with the full exemption granted to medical devices up to 800 pounds of volatile organic compound (VOC) per year granted in both R307-350 and R307-353 and asked for language that would add conditions to the exemption. In addition, during the meeting the Board received a request to add an exemption to R307-355 for the cleaning of laser hardware, scientific instruments, and high precision optics. The Board also asked staff to bring back proposed language to include the exemption in R307-355. Staff reviewed the Board's requests and is proposing the amendments. Staff recommended that the Board propose for public comment these rules as amended.

- Arnold Reitze moved to propose R307-350, R307-353, and R307-355 for public comment as amended. Erin Mendenhall seconded. The Board approved unanimously.

Thomas Gunter was introduced as DAQ's new rules coordinator.

VI. Informational Items.

A. PM2.5 State Implementation Plan Update. Presented by Bill Reiss.

Bill Reiss, Environmental Engineer at DAQ, stated that in September 2017 staff informed the Board that we are no longer on track to meet the deadlines for the serious area SIPs. Much of the technical work has been compiled for each SIP which includes: a validated air quality model; a base year emissions inventory; draft emissions inventories for all the other years that could potentially be utilized in the SIPs; and work is still being done on the best available control technology (BACT) analyses for stationary sources. Staff are still determining whether attainment can be demonstrated in 2019, which is the year containing our statutory attainment date. If attainment can be demonstrated in 2019, the SIPs would be relatively simple to piece together. If not, additional work and time will be needed. Even though the BACT work is not complete, staff went back through the inventories on a case-by-case basis. That model showed more reductions in emissions from the vehicle emission program but those results also showed we would still be over the standard at Rose Park and Hawthorne in 2024. The Provo area showed values below the standard.

Since the difficulties are mostly confined to Rose Park and Hawthorne, DAQ is going to separate the two nonattainment areas of Salt Lake and Provo where Provo will be put on a faster track. There are only two stationary sources in the Provo area and the BACT work is almost complete on those sources, which means the projection emissions inventory for Provo can be completed and the 2019 model is being run right now. The results for Provo are expected to show attainment in 2019. However, this all depends on the starting point. EPA's modeling guidance allows some flexibility in selecting the starting point for the monitored design value. Staff plans to finish the final internal audit for the Provo reports and plan to have them posted for public review at the end of January 2018.

For now, the moderate SIP for the Logan area should be sufficient as long as EPA does not reclassify the area. The Provo and Salt Lake SIPs are due at the end of 2017, and DAQ will not be able to meet this deadline. For the Provo nonattainment area, if we can show attainment in 2019 that SIP could be completed at the end of the first quarter in 2018, but again it depends on the starting point.

It was commented that research by the Kem Gardner Policy Institute shows the greatest population growth along the Wasatch Front is going to be in Utah County, in particular west of Utah Lake and how is DAQ predicting population growth in its models. Staff responded that DAQ is applying the REMI modeling approach to stationary sources and results show that area sources represent a fair piece of the VOC and NOx emissions.

B. Air Toxics. Presented by Robert Ford.

C. Compliance. Presented by Jay Morris and Harold Burge.

D. Monitoring. Presented by Bo Call.

Bo Call, Monitoring Section Manager at DAQ, updated the Board on monitoring information noting a current inversion is setting up along the Wasatch Front and Cache Valley and is forecasted to last a couple of weeks.

E. Other Items to be Brought Before the Board.

Mr. Martin stated that the second Science for Solutions, a Utah air quality research conference, will be held the end of March or first of April at Weber State University. More information will be sent to the Board as it becomes available. Also, Mr. Martin and Joe Thomas of DAQ were involved with research about vehicle cold starts and idling studies. As a result some informational posters were developed and distributed throughout the Cache Valley.

F. Board Meeting Follow-up Items.

- R307-403 will lapse as a result of today's decision. Staff will bring back a revised R307-403 at a future meeting when the ammonia precursor analysis has been completed.

Meeting adjourned at 2:30 p.m.

ITEM 4

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Department of
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Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-087-17

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Director

FROM: Sheila Vance, Environmental Scientist

DATE: December 20, 2017

SUBJECT: FINAL ADOPTION: Change in Proposed R307-150. Emission Inventories; R307-401. Permit: New and Modified Sources; R307-504. Oil and Gas Industry: Tank Truck Loading; R307-506. Oil and Gas Industry: Storage Vessel; R307-507. Oil and Gas Industry: Dehydrators; R307-508. Oil and Gas Industry: VOC Control Devices; R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-510. Oil and Gas Industry: Natural Gas Engine Requirements; and New Rule R307-505. Oil and Gas Industry: Registration Requirements.

On September 6, 2017, the Board approved for public comment the above proposed amendment and new rules. DAQ recommended the proposed changes, as a way to streamline the permitting of minor oil and gas sources, by replacing the current source-by-source permitting process with what is referred to as a permit-by-rule (PBR). The proposed PBR will benefit producers, DAQ, and the public as it reduces permitting costs; eliminates several administrative steps in the permitting process, reducing permit engineering time; and ensures consistency of operational requirements.

The following table summarizes each rule and provides an estimated cost or savings for each rule.

Rule	Summary	Potential Cost/Savings
R307-150	Adds Oil and Gas sources statewide to the triennial emission inventory requirement	Estimated to be $150 per well site, annualized to $50 as over a 3 year period.
R307-401	Exempts minor source Oil and Gas well sites from obtaining an air approval order	No cost for oil and gas well sites. Cost savings for well sites that would have had to obtain an air approval order. An average cost for a well site is $1,800.

Rule	Summary	Potential Cost/Savings
R307-504	Truck tank loading emission controls required for oil and gas well sites that are required to control storage vessel emissions.	Original estimate was no cost to operators. Through public comment and internal review there is a potential cost to operators that complied with federal NSPS OOOO and met the Utah small source exemption (R307-401-9). The cost for equipment to control truck tank loading is potentially $10,000 per well site and annualized to $750 per ton of VOCs controlled. The 2014 emission inventory indicated 244 sites potentially impacted by this rule in the Uinta Basin which is approximately 15% of sites; analysis suggests it would be a smaller percentage statewide .
R307-505	Requirement for all oil and gas sources to register with DAQ	Original estimate was $100 per registration. To utilize the existing filing fee established, the cost would be $250 per registration for small sources and $500 for larger sources that have not obtained an air approval order. These fees are in accordance with the fee schedule established by the legislature. Large sources will experience a cost savings. However as current small sources may register rather than being required to, it will be a cost for small sources. It is estimated there are 30 businesses impacted by this rule, with 10 at least being small businesses. Businesses may have several sites, and up to several hundred sites for larger businesses, so will have compounded cost. Sites will have six months to register and additional time to pay fees.
R307-506	Storage Vessel Controls	Original potential costs to new oil and gas well sites indicated that there could be a $40,000 to $60,000 cost to control storage vessels where they may not have had to otherwise. This was an incorrect cost estimate as new well sites have to meet federal NSPS standards that require them to control sites or would have to control emissions in accordance with Utah state minor source permit requirements or install controls to potentially meet small source exemption requirements. Either way, controls would be required to be installed. No additional costs are estimated for this proposed rule.
R307-507	Dehydrator Requirements	No additional costs are estimated for this proposed rule.
R307-508	VOC control requirements	Original potential costs to new oil and gas well sites indicated that there could be a $40,000 to $60,000 cost to control VOCs where they may not have had to otherwise. This was an incorrect cost estimate as new well sites have to meet federal NSPS standards that require them to control sites or would have to control emissions in accordance with Utah state minor source permit requirements or install controls to potentially meet small source exemption requirements. Either way, VOC control devices would be required to be installed. No additional costs are estimated for this proposed rule.

Rule	Summary	Potential Cost/Savings
R307-509	Leak Detection and Repair Requirements (LDAR)	Original cost estimated was approximately $600 per oil and gas well site. This cost could be applicable to well sites that had complied with federal NSPS requirements under OOOO and met the Utah state small source exemption (R307-401-9). The 2014 emission inventory indicated 229 sites would potentially be impacted by this rule in the Uinta Basin; assume a smaller number statewide .
R307-510	Engine Requirements	No additional costs are estimated for this proposed rule.

The public comment period was held from October 1 to November 15, 2017. Two public hearings were held, one in Salt Lake City on October 19, 2017, and on October 25, 2017, in Vernal, Utah. At the Salt Lake City public hearing fifteen individuals commented on the proposed rule, and twelve individuals commented at the Vernal public hearing. Most of the comments were generally supportive of the rules but the commenters asked for additional strengthening amendments. Other commenters expressed concerns about some of the rules' requirements. Those individuals followed up with written comments that are addressed in the response to comments below.

Many commenters recommended the following additional strengthening requirements: (1) expand the rules to apply to methane as an air pollutant; (2) increase the frequency of inspections for leaks to quarterly or at a minimum semi-annually for all sources (not just those with emission control devices); and (3) improve the recordkeeping transparency. These recommendations were detailed in written comments submitted to the DAQ by the Environmental Defense Fund (EDF) and others that are responded to in the response to comments below. No changes were made to the rules in response to these comments.

Other concerns and questions regarding the proposed rules did result in changes and clarification to the rules. The changes are summarized as follows:

R307-150-9: The rule was amended to clarify that applicability for the emission inventory requirement is based on one ton of uncontrolled actual emissions of an individual criteria air pollutant.

R307-401-10: The rule was amended to clarify that the exemption for oil and gas wells as defined by 40 CFR 60.5430a does include centralized tank batteries (the 40 CFR definition only includes centralized tank batteries for applicability of fugitive emissions standards).

R307-504: The rule was amended to clarify the definition of "vapor capture line." The change to the definition does not substantially alter the requirements of the proposed rule but makes compliance with the rule easier. Applicable sites currently in operation will have 18 months to comply with the proposed rule.

R307-506: The proposed rule was amended to clarify the definition of a well site, the definition of uncontrolled emissions, how emergency relief storage vessels would be regulated under the rule, and to broaden the methods for determining emissions and type of emissions (uncontrolled versus controlled). These changes provide more flexibility to determination of emissions and clarify applicability of rules. The emergency relief storage vessels changes were due to questions regarding their applicability to the proposed rule. This required the addition of requirements for such vessels as they are regulated differently from production and operational vessels.

R307-507: The proposed rule was amended to clarify the definition of well site, the definition of uncontrolled emissions and the addition of a monthly visual inspection of dehydrators. The addition of the monthly inspection is in accordance with federal NSPS requirements and current oil and gas well approval orders. This does not significantly affect current operation of dehydrators as they are already performing the inspections. The requirement was added because it was missed in the original proposal.

R307-508: The proposed rule was amended to clarify the definition of a well site and requirements. The clarifications did not substantially change the proposed requirements.

R307-509: The proposed rule was amended to clarify the definition of a well site, add missing definitions, and to clarify that volatile organic compound (VOC) control devices that meet the requirements of federal NSPS OOOOa automatically meet the requirements of this rule. The clarifications do not substantially change the proposed requirements.

R307-510: The proposed rule was changed to reflect more specific engine requirements that will allow sources to better understand the intent of the proposed engine requirements. The changes do not substantially change the proposed requirements.

Staff received multiple written comments on this proposal that are summarized below.

Recommendation: Staff recommends that the Board adopt new rule R307-505 as proposed and R307-150, Emission Inventories; R307-401, Permit: New and Modified Sources; R307-504 Oil and Gas Industry: Tank Truck Loading; and new rules R307-506, Oil and Gas Industry: Storage Vessels; R307-507, Oil and Gas Industry: Dehydrators; R307-508, Oil and Gas Industry: VOC Control Devices; R307-509, Oil and Gas Industry: Leak Detection and Repair Requirements; and R307-510, Oil and Gas Industry: Natural Gas Engine Requirements as amended.

Response to Comments

General Comments

Written comments were received from 11 individuals: Environmental Defense Fund (EDF); Breathe Utah; Citizens for Clean Air Colorado; the Mormon Environmental Stewardship Alliance (MESA) and several small businesses located in Salt Lake City, Moab, Jensen and Vernal. It should be noted that 388 signatures were submitted in support of EDF's and Breath Utah's comments. MESA's comments included 86 signatures in support. Comments submitted by organizations other than EDF listed above were generally the same as the more detailed comments provided by EDF and are addressed in the following response to EDF's comments.

EDF Comments

Questions and comments excerpted from original document.

EDF Comment #1: We urge the DAQ to expand the scope of the draft regulations to require the control of hydrocarbons.

DAQ Response: The intent of this proposed rule-making was to gather necessary information regarding gas and oil operations in the state of Utah to ensure compliance with current requirements and to provide a streamlined permitting process for oil and gas well sites. To institute a permit-by-rule (PBR) for such sources, the proposed rules reflect current requirements for oil and gas well sites that require a minor source permit. To expand the rule to include control of hydrocarbons would go beyond the scope of what has been proposed. It can be noted that although the rules do not require control of all hydrocarbons, the controls required for VOCs are also effective for controlling methane and other hydrocarbon emissions. No changes were made as a result of this comment.

EDF Comment #2: We recommend the adoption of quarterly inspection frequency.

DAQ Response: As stated in the response for EDF Comment #1, the proposed rules reflect current requirements for oil and gas well sites that fall under a minor source permit. At this time there is a semi-annual LDAR inspection requirement for minor source permits issued to sources. No changes were made as a result of this comment.

EDF Comment #3: In the event that DAQ does not require operators inspect their facilities quarterly, we urge DAQ to establish a semi-annual inspection requirement applicable to all well sites - not just to those subject to control requirements.

DAQ Response: The proposed rules were developed to reflect current requirements for oil and gas well sites. Current minor source permits require a storage vessel or group of storage vessels that have uncontrolled actual emission greater than 4 tons per year (tpy) of VOCs and sources with dehydrators that have uncontrolled actual emissions greater than 4 tpy individually or combined with storage vessels to control emissions and perform LDAR inspections. This requirement is reflected in the proposed rules. If a source is not required to control emissions currently, they are not required to perform LDAR inspections. No changes were made as a result of this comment.

EDF Comment #4: Lastly, we urge DAQ to expand the scope of the LDAR program to apply to pneumatic devices, or to adopt a separate provision requiring operators inspect pneumatic controllers, as Colorado, Ohio and California have all done.

DAQ Response: Again, the proposed rules reflect current LDAR requirements based on NSPS Subpart OOOOa requirements. NSPS Subpart OOOOa does not consider natural gas-driven pneumatic controllers as fugitive emissions components. No changes were made as a result of this comment.

EDF Comment #5: We strongly urge the agency to adopt a robust alternative compliance pathway that is minimally prescriptive and specifically creates an entry point for methodologies that are at least as effective in enabling emission reductions as those specified in its leak detection rules.

DAQ Response: The proposed rules reflect current requirements for LDAR. As new methodologies are presented and vetted by DAQ rules can be updated to reflect advancements in LDAR technologies. No changes were made as a result of this comment.

EDF Comment #6: First we urge DAQ to require 98%, control rather than 95%, of tank emissions. Second, we urge DAQ to require provisions that will ensure that tank controls are designed and operated to ensure proper and continuous operation. Recent inspections by EPA and the state of Colorado have revealed that inadequately designed and operated storage tank vapor control systems can result in very significant emissions.

DAQ Response: The proposed rules reflect NSPS OOOOa requirements for 95% control efficiency. Combustion devices are designed to meet a 98% efficiency but may not actually meet that percentage due to the variability in field conditions and operations. The existing rule, *R307-501 Oil and Gas Industry: General Provision*, requires proper design and operation of air pollution control equipment. No changes were made as a result of this comment.

EDF Comment #7: (glycol dehydrators) We urge the DAQ to strengthen the control efficiency requirements, however, consistent with our comments for tanks above.

DAQ Response: See response for EDF Comment#6.

Western Resource Advocates (WRA) Comments
Questions and comments excerpted from original document.

WRA Comment #1: Thus, the proposed rules should be amended accordingly to apply BACT to methane.

DAQ Response: See response to EDF Comment #1. In addition, R307-401-9(5) states: "A stationary source that is not required to obtain a permit under R307-405 for greenhouse gases, as defined in R307-405-3(9)(a), is not required to obtain an approval order for greenhouse gases under R307-401. This exemption does not affect the requirement to obtain an approval order for any other air pollutant emitted by the stationary source." Because methane is a greenhouse gas, a source is not required to obtain a permit and go through a best available control technology (BACT) analysis for methane. No changes were made as a result of this comment.

WRA Comment #2: Thus, as confirmed by the regulations adopted in other major oil and gas producing states, quarterly LDAR inspections are BACT. As a result, the proposed rules should be amended to reflect that inspections of this frequency constitute achievable controls and are necessary to secure the maximum reductions of pollutants from oil and gas facilities.

DAQ Response: Current BACT for minor source permits for oil and gas wells has been established to be semi-annual, and the proposed rules reflect BACT. No changes were made as a result of this comment.

WRA Comment #3: Thus, as demonstrated by the requirements adopted in Colorado, California and Ohio, inspecting pneumatic controllers using LDAR is cost effective and feasible and therefore constitutes BACT. As a result, the proposed rules should be amended to require LDAR for pneumatic controllers as necessary and appropriate to achieve the maximum emission reductions from these sources of air pollution.

DAQ Response: Current BACT for minor source permits for oil and gas wells is reflected in the proposed LDAR rule which is based on NSPS OOOOa. NSPS Subpart OOOOa does not consider natural gas-driven pneumatic controllers as fugitive emissions components. No changes were made as a result of this comment.

WRA Comment #4: Storage tanks are a significant source of air pollution. To maximize emission reductions from these sources of emissions, Wyoming and Colorado require operators to control 98% of the emissions from tanks using devices such as flares and vapor recovery units. Accordingly, a similar control effectiveness requirement is appropriate in Utah.

DAQ Response: The proposed rules reflect current minor source BACT based on NSPS OOOOa requirements for 95% control efficiency. No changes were made as a result of this comment.

WRA Comment #5: To address these issues, we request that the proposed rules be amended to require source operators to submit periodic reports characterizing their emissions and establishing their compliance with the standards and limitations the rules set forth. As a function of such reporting requirements, the public will have access to this information via an open records act request and will have the opportunity to assess whether the proposed rules are effective at reducing air pollution and whether the sources are complying with the rules.

DAQ Response: Sources subject to R307-150 must submit emission data to the DAQ according to R307-150. Emission data for oil and gas sources will be submitted to the DAQ under new rule R307-150-9. DAQ will review this information to ensure compliance with the applicable requirements of R307.

The commenter is incorrect in its statement that sources "must provide the Division with periodic reports that establish whether their facilities are complying with the limitations and standards set forth in the proposed rules." The commenter references Utah Administrative Code R307-102-1(2); but this regulation does not support the commenter's argument. This regulation requires owners and operators of air pollution sources to provide to the Director periodic reports that are required under Section 19-2-104(1)(c) along with any other information to assist the Director in determining compliance. *See* Utah Admin. Code R307-102-1(2). Any information submitted to the Director under this rule must then be available to the public. The reports referenced in the regulation are defined in Utah Code Section 19-2-104(1)(c) as periodic reports "containing information relating to the rate, period of emission, and composition of the air pollutant." Utah Code Ann. § 19-2-104(1)(c). None of the records that are required in the proposed rules R307-504, R307-505, R307-507, R307-508, R307-509, and R307-510 fall under the definition of reports in Section 19-2-104(1)(c). These records would not show rates, periods of emissions, or composition of specific air pollutants; and are not reports as defined in Section 19-2-104(1)(c). Consequently, the proposed rules do not violate Rule 307-102-1(2).

Section 19-2-104(1)(c) does not require DAQ to include rule language that would require a source to submit compliance records to DAQ. Section 19-2-104(1)(c) grants authority to the Utah Air Quality Board to make rules requiring sources to "file periodic reports containing information relating to the rate, period of emission, and composition of the air pollutant" and "provide access to records relating to emissions which cause or contribute to air pollution." Utah Code Ann. § 19-2-104(1)(c). This is a general authorization to the Board to promulgate rules that would require filing of periodic reports and access to the records related to emissions that cause air pollution. The purpose of this access is to facilitate DAQ's regulatory oversight, but the statute says nothing about access for the public and does not impose a requirement that all compliance records must be submitted to the Director.

The commenter is incorrect that the proposed rules contain no reporting requirements. R307-150-9 requires sources to report emission inventory data to the DAQ at least every three years. The remaining proposed rules do not contain reporting requirements; however, as mentioned above, reporting requirements are not imposed by either state or federal law.

The commenter refers to a recent decision issued by the Third District Court, claiming that the court upheld the DAQ Director's position that "the public is not entitled to review monitoring or compliance reports or records maintained by the source." First, the commenter misstates the court's decision. The public may be able to review records and reports maintained by the source if they are produced in discovery or pursuant to a subpoena, but such review is not available under GRAMA because the Director is not obligated under GRAMA to procure records from the sources at a third party's request. The court held that only records in custody of the Director are records subject to GRAMA. *See* Memorandum Decision at 3-4, WRA v. UDEQ et al., Case No. 170900028 (Third Dist. Ct. April 5, 2017).

Second, the commenter appears to acknowledge the Third District Court's decision, but fails to explain how this decision supports its argument that the law requires mandatory submission of compliance reports or records maintained by the sources to the Director. The decision only resolved a narrow question as to whether the documents maintained by the sources are subject to GRAMA. The court did not decide whether the Clean Air Act, the Utah Air Conservation Act, and air quality regulations mandate that the sources submit records to DAQ. In fact, the court never reached that question, dismissing WRA's claims "for failure to state a claim . . . since there is no state and federal law that requires DAQ to obtain records it does not possess." *Id.* at 5, *WRA*, Case No. 170900028.

To the extent the commenter asserts that the proposed rules must require submission of compliance reports and documents to the Director, the law does not support the commenter's argument. No changes were made as a result of this comment.

<u>Western Energy Alliance (WEA) Comments</u>
Questions and comments excerpted from original document.

WEA Comment #1: Proposed section R307-504-4 would require that any facility mandated to control storage tanks pursuant to R307-506 also would be required to control loadout emissions. Doing so would necessitate addition of piping and equipment. This, by definition, would entail retrofitting existing sources with new equipment.

DAQ Response: The intent of the cited portion of the memorandum to the Utah Air Quality Board was to state that "retrofitting" of equipment would not be likely for those who placed voluntary controls to become a small source exemption. The 2014 emission inventory collected for the Uinta Basin oil and gas well sites identified 244 sources on state regulated lands that reported that they had controls on storage vessels but did not have an approval order (sources with an approval order are exempt from this rule). This represents approximately 15% of oil and gas well sites with storage vessels. Further analysis suggests a smaller percentage of affected sources statewide . The DAQ acknowledges that these 244 sources would now need to comply with R307-504 if adopted and will require retrofitting for truck loading operations. As the larger significant cost for oil and gas well sites is the installation of VOC control devices, it is reasonable to require the small percentage of affected sources to control truck loading operations, which can significantly reduce emissions from the oil and gas well site. However, as this rule will require installation of equipment to these sources, the rule has been amended to include an 18 month implementation period for existing sources. The following language has been added to R307-504-4(2):

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

WEA Comment #2: Similar to the issue described immediately above, it appears the structure of R307-506 effectively eliminates the small source exemption for a certain category of facilities.

DAQ Response: It is true that the proposed rules now require oil and gas sources that meet the small source exemption to register with the agency, where the current language in R307-401-9 states that exempted small sources "may submit a written registration notice to the director." The proposed rules have been drafted in such way that any source that obtained an air approval order is exempt from the registration rule. Those sources that now will have to register will only be required to provide registration information to the DAQ. To meet the small source exemption sources may have had to install controls to meet the 5 tpy or less requirement, which is what these proposed rules require. In essence, though the source has to register where they haven't had to before, any additional equipment requirements are those that most likely the source would have had to install to have emissions 5 tpy or less.

The DAQ believes that establishment of the registration provides verification of the location of such sources and the type of equipment on site. The DAQ understands that there are potentially 5,000 oil and gas facilities on land under state jurisdiction, with approximately 1,800 of those having air approval orders. This leaves potentially 3,200 sources that are unknown to the agency. It is important to understand where these sources are and what equipment they have on site.

No changes were made as a result of this comment.

WEA Comment #3: By virtue of these federally enforceable controls, the OOOO sites may be below the 5 tpy VOC threshold for obtaining an AO and therefore may not have state permits. However, it appears R307-504 would require these controlled sites to now control truck loadout emissions. Since truck loadout isn't currently controlled at these locations, they would be subject to retrofit requirements.

DAQ Response: DAQ agrees that some sources that have installed VOC control devices under 40 CFR 60 Subpart OOOO but did not obtain a state approval order will be required to now control truck loadout emissions. These sites may currently fall under small source exemption thresholds, but this would not have been true when 40 CFR 60 Subpart OOOO was triggered due to the nature of the subparts per storage vessel emission value of 6 tons or greater. Given that sites generally have multiple vessels, coupled with loading loss emissions, and fugitive emissions, we are unaware of any sources where OOOO would have applied and the need to obtain an approval order would not have. However, as this rule will require installation of some equipment, the rule has been amended to include an 18 month implementation period for existing sites. The following language has been added to R307-504-4(2):

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

WEA Comment #4: With respect to R307-507-4, Dehydrator Requirements, the Alliance notes that controls for dehydrators are triggered at a well location through either an individual VOC emission total of 4 tons per year or a combined VOC emissions total of 4 tons per year for dehydrators and storage vessel emissions. We believe UDAQ is incorrectly applying BACT by combining emissions units. Application of BACT is set forth under EPA regulation (40 C.F.R Part 52) and establishes that a source "shall apply best available control technology for each regulated NSR pollutant that it

would have the potential to emit in significant amounts" and should be applied to each "emissions unit." 40 CFR 52.21(b)(12).

DAQ Response: DAQ disagrees with this comment. It is true that dehydrators and storage vessels are different pieces of equipment; however, they both emit VOCs and can be controlled by the same device. BACT applies to a stationary source, which is defined in 40 CFR 52.01 as "any building, structure, facility, or installation which emits or may emit an air pollutant for which a national standard is in effect." Given the above definition, the source would be the oil and gas well pad, and controlling emissions from both a dehydrator and storage vessels is technically feasible. The threshold for economic feasibility is 4 tpy of VOC emissions being routed to a combustor; the source of those VOC emissions on the well pad is not relevant if the emissions can be controlled by the same piece of equipment as they can here. No changes were made to the rule as a result of this comment.

WEA Comment #5: In order to further minimize reporting burden, we encourage UDAQ to harmonize the registration and emissions inventory sections as much as possible. Specifically, R307-505-3(4) requires the registration include "process description, capacity and quantity of emitting equipment on-site, fuel type of combustion related equipment… emissions control devices installed, emissions and certification that the facility is in compliance with R307-506 through R307-510" (emphasis added). It's unclear how reporting facility emissions, and then separately reporting emissions through the inventory process adds value for UDAQ's information collection needs, yet it is clearly duplicative for industry.

DAQ Response: In developing the registration rule, and the related reporting requirements, DAQ worked methodically to prevent duplicative reporting between the registration and emissions inventory. Basic company and source information such as company name, mailing address, source contact, and source location are required in both cases. However, this is necessary as all detailed reporting information relates back to this basic information. Users wanting to register the same set of sources that they reported in the emissions inventory can copy and paste the basic data from the emissions inventory to the registration. Additionally, the detailed information collected via the registration, which is different from what is collected via the emissions inventory, enables DAQ to know what equipment is installed on-site at a source and what specific oil and gas rules are applicable to that source. No emissions data is required to be reported in the registration. However, users may optionally report emissions rather than site-wide throughput for storage vessels, according to R307-506-4 (b) to demonstrate VOC emissions of less than four tons per year. The emission demonstration based either on site-wide throughput or reported emissions shall be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP-42 Chapter 7.

The registration and the emissions inventory serve very different purposes. The registration informs DAQ of the current state of the oil and gas industry in Utah. The registration is the sole way operators inform DAQ when a new source will begin operations, as notice of intents (NOIs) will no longer be used in these instances. Operators will also inform DAQ of sources that are currently operating. Currently, unless a source has a Utah state approval order or has voluntarily registered as a de minimis source, DAQ does not know that the source exists or has any other information about the source. While DAQ does have information about the sources that reported their emissions inventory, there is no way of knowing how inclusive the dataset is. Additionally, the emission inventory is collected on a tri-annual basis. During the time between inventories being collected, many sources could begin operations, and many changes could be made to existing operations, all without DAQ's knowledge. The registration enables DAQ to know, at any point in time, what oil and gas operations exist in the state. This is especially important for compliance operations within DAQ because this data informs compliance inspectors about sources in the state, their equipment, and applicable rules to ensure sources are compliant. The purpose of the emissions inventory, on the other hand, is to inform DAQ of the specific emissions associated with an oil and gas source, and the oil and gas source category as a whole. Much more detailed operating information is needed for emissions inventory reporting.

Finally, it should be noted that registration is only required to be completed once per source. Once a source is registered, an operator does not need to take any further action unless changes to company name, removal or addition of control devices, or termination occur. In these cases, the operator just needs to update its registration to reflect the changes.

WEA Comment #6: The inventory requirements of R307-150-3(5) also stipulate facilities with "actual emissions greater than one ton per year" report, yet they do not specify one ton of what pollutant, or whether that one ton is for a single pollutant or combined emissions. We recommend UDAQ change the rule language to specify one ton per year of a single criteria pollutant or hazardous air pollutant.

DAQ Response: The DAQ agrees that the language of R3017-150-3(5) needs to be clarified to stipulate that we are referring to one ton per year of uncontrolled actual emissions for a single pollutant, including PM_{10}, $PM_{2.5}$, NOx, SOx, CO, or VOC. Language in R307-150-3(5) has been changed as follows:

(5) R307-150-9 applies to sources with Standard Industrial Classification codes in the major group 13 that have uncontrolled actual emissions greater than one ton per year for a single pollutant of PM_{10}, $PM_{2.5}$, oxides of nitrogen, oxides of sulfur, carbon monoxide or volatile organic compounds. These sources include, but are not limited to, industries involved in oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; and natural gas processing plants and commercial oil and gas disposal wells, ponds and sites.

WEA Comment #7: While we appreciate the inventory requires significant review and processing by UDAQ, the proposed deadline of April 15th will be remarkably difficult to meet, given that it also overlaps the PBR's new registration requirements. We recommend June 1st as a more appropriate deadline.

DAQ Response: In the 2014 oil and gas emissions inventory, DAQ received data for 8,533 sources. It took a significant amount of time for DAQ to perform QA/QC of this data, transfer this data to a database system, and summarize this data for reporting to the triannual National Emissions Inventory (NEI) as required by EPA. There are likely to be even more sources reported in the 2017 emission inventory, as the inventory will now apply statewide rather than just to the Uinta Basin. Therefore, it is likely that the time required for reviewing and processing the received emissions inventory data will also increase. Additionally, operators were also given four months to submit the 2014 emissions inventory, which was not an issue. DAQ recognizes that there is overlap with the Permit by Rule's (PBR) registration requirements, but as noted in DAQ's response to WEA Comment #5, the registration requires a minimal amount of information to be reported for a source, and thus should not take a significant amount of time to complete. Finally, the April 15th deadline is consistent with the inventory reporting deadline for all other source categories that report emission inventories to DAQ.

WEA Comment #8: Regardless of the structure selected, the fees contemplated by UDAQ will likely be significant and impose substantial one-time costs on operators, many of which are struggling in the current economic environment. No operator will have hundreds of thousands of dollars in its current budget cycle for Utah asset registration, making it critical that UDAQ provide operators time to plan for such significant expenses. We recommend UDAQ delay fee collection by one year to accommodate the budget planning cycle.

DAQ Response: The rule as proposed provides six months for an existing source to register with DAQ. Invoices will be assessed after registration. Payment will be due no later than 180 days after DAQ issues the invoice.

WEA Comment #9: We also suggest that UDAQ clarify R307-505-3(4) where it states registrants must provide "certification that the facility is in compliance with R307-506 through R307-510." However, it is unclear how a small source claiming exemption because its emissions are below the specified threshold could certify compliance. Rather, for those sources it would make sense for them to certify they are exempt from the requirements of R307-506 through R307-510. Such a change would minimize the potential misinterpretation of compliance obligations.

DAQ Response: The applicability of rules R307-506 to R307-510 is based on the specific components and/or equipment the rule refers to (i.e. storage vessel, dehydrator, VOC control device, fugitive emission component, natural gas-fired engine) being installed at the well site. While some sources may not be subject to the requirements listed in the rule (small sources claiming exemption), all registrants will be able to use the registration process to evaluate each rule's applicability and determine whether or not any of the rules apply to them. So long as an operator has examined each rule's applicability, even if none of the related rule requirements apply, they would be in compliance with the rule and would be able to certify compliance as required in R307-505-3(4). No changes were made to the rule in response to this comment.

WEA Comment #10: The requirement to submit registration information prior to construction will also undermine the registry's accuracy. Prior to construction, many operating conditions will be unknown and as a result, industry will be forced to use conservative emissions estimates that will almost certainly be overstated when compared to actuals. We suggest that the registration deadline be 60 days after construction, which would ensure that UDAQ is collecting the most accurate information based on actual operating conditions.

DAQ Response: R307-505-3(1) states "An owner or operator of a source identified in R307-505-2 that begins operations on or after January 1, 2018, shall register with the director 30 days prior to commencing operation." There is no requirement to submit registration information prior to construction, only prior to commencing operation. No changes were made to the rule in response to the comment.

WEA Comment #11: First, the definition of "Vapor Capture Line" in R307-504-2 specifies that "[t]he other end of the vapor capture line is connected to an existing tank battery or enclosed vapor combustor for the destruction of VOC emissions." We suggest that DAQ revise that provision so that it does not eliminate other options operators may seek to use such as a vapor recovery units or fuel gas systems. For example, the language could be amended to say "the other end of the vapor capture line is connected to a control device or to a process resulting in a minimum of 98% destruction efficiency."

DAQ Response: DAQ agrees with this comment. It was not our intent to eliminate future options that have equivalent control efficiencies. The definition for "Vapor Capture Line" has been amended in R307-504-2 as follows:

"Vapor Capture Line" means a connection hose, fitted with a valve that can be connected to tanker trucks during truck loading operations. The vapor capture line shall be designed, installed, operated, and maintained to optimize capture efficiency.[~~used to collect VOC emissions from truck loading operations. The other end of the vapor capture line is connected to an existing tank battery or enclosed vapor combustor for the destruction of VOC emissions~~.]

WEA Comment #12: Second, we also have concerns with the requirements of R307-504-4 that stipulate the vapor capture line shall achieve no less than 70% capture efficiency. We are not aware of any methodology that could be used to demonstrate that the vapor capture line achieves 70% capture efficiency. As a result we request that UDAQ remove this requirement from R307-504-4.

DAQ Response: DAQ agrees with this comment. The 70% capture efficiency was pulled from AP-42 Chapter 5.2; upon further review this 70% capture efficiency is assumed. DAQ's intent of including the 70% capture efficiency was to ensure properly installed and maintained equipment that could handle the emission stream. The definition of "Vapor Capture Line" has been amended to accommodate this intent. R307-504-4(2) has been amended as follows:

(2) VOC emissions during truck loading operations shall be controlled at all times using a vapor capture line. The vapor capture line shall [~~achieve no less than 70% capture efficiency and 98% destruction efficiency (95% efficiency from VOC control device and 3%] from auto ignitor requirements of R307-503) resulting in an overall control efficiency of no less than 68.6%. An equivalent control technology can be utilized if approved by the director and capable of meeting or exceeding a 68.6% overall control efficiency.~~]be connected from the tanker truck to a control device or process, resulting in a minimum 95 percent VOC destruction efficiency.

WEA Comment #13 ...the emission threshold in R307-506-4(2)(b) should be revised to indicate whether the threshold of 4 tons per year of VOCs refers to actual emissions after controls or uncontrolled emissions. We believe a strong case can be made that the threshold should be set at controlled emissions; since the operator already would have invested significant resources in controlling emissions, additional controls likely would not be cost effective.

DAQ Response: DAQ disagrees with this comment. The intent was to mimic current day BACT determinations being made in the permitting section, which requires sources to control VOC emissions when they are over the uncontrolled threshold of 4 tpy. R307-506-4(2)(b) has been amended to correct this issue. A definition of "Uncontrolled Emissions" has also been added in the definitions section in R307-506-2.

"Uncontrolled emissions" means actual emissions or the potential to emit without consideration of controls.

WEA Comment #14: It is unclear why a specific version of software needs to be referenced at all; rather any choice of software or calculations based on AP-42 emission factors would appear to suit UDAQ's needs here. As written, this provision is needlessly prescriptive and would create unnecessary compliance issues with no environmental benefit.

The same section also specifies VOC flash calculations be made using the Vasquez-Beggs equation, and that any alternative method must be approved by the director. Again, this is needlessly prescriptive. The Vasquez-Beggs equation is not suitable in all situations, and should not be the only approved methodology. Instead, we suggest UDAQ employ the language used by the EPA in NSPS Subpart OOOOa: "The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology…". We also request clarification on how director approval will work, and whether approvals will be company-specific or industry-wide.

DAQ Response: DAQ agrees with this comment. The decision to require a specific methodology in the rule was made so we could compare all sources equally. Several studies, most notably the work done by the Texas Commission on Environmental Quality (TCEQ), show methods of calculation, even using different acceptable software, can have significant impacts on emission estimations. However, given the requirement for site-specific sampling, the variations among calculation methodologies are likely to be less significant and as such we have amended R307-506-4(2)(b) to allow any calculation methodology based on AP-42 Chapter 7.

(i) VOC working and breathing losses, and flash emissions shall be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP-42 Chapter 7.
[~~(ii) VOC flash emissions shall be calculated using site-specific sampling data and the Vasquez-Beggs Equation.~~
~~(iii) VOC emissions determined by an alternative method approved by the Director.~~]

WEA Comment #15: "throughput of greater than 8,000 barrels of crude oil per year on a rolling twelve-month basis makes no mention of condensate. We recommend condensate be added to the definition for clarity.

DAQ Response: DAQ agrees with this comment. Condensate has a much different emissions profile with a higher vapor pressure resulting in a lower throughput. R307-506-4(2) has been amended as follows:

(2) All storage vessels located at a well site [~~A storage vessel or collection of storage vessels,~~]that [~~is~~]are in operation as of January 1, 2018, with a site-wide throughput of 8,000 barrels or greater of crude oil or 2,000 barrels or greater of condensate per year on a rolling 12-month basis shall comply with R304-506-4(2)(a) unless the exemption in R307-506-4(2)(b) applies.

WEA Comment #16: First, the production data used to determine applicability must only be kept for three years, so the benefit of retaining documents indefinitely is unclear. Second, requiring retention of emission data calculations for the life of the well is often infeasible given how often wells change owner or operator. Instead, we suggest that emissions data records be retained be kept for three years.

DAQ Response: DAQ agrees with this comment. R307-506-5 has been amended to correct the record retention period as follows:

(3) Records of emission calculations, actual emissions, and site-specific sampling data used to determine compliance with R307-506-4(2)(b) shall be kept for a period of three years, post registration.[~~as long as the well site is in operation.~~]

WEA Comment #17: Finally, we also note that while extensive record keeping requirements are associated with the control device in R307-508-4, there is no specified record retention period. We recommend that UDEQ specify a record retention period for clarity.

DAQ Response: DAQ agrees with this comment. R307-508-4 has been amended to include specific record retention periods to correct this issue.

1) The owner[~~,~~]or operator shall keep and maintain records of [~~the following:~~
~~(a)~~] the VOC control device's control efficiency guaranteed by the manufacturer. These records shall be retained for the life of the control equipment on site.
([~~b~~]2) The owner or operator shall keep and maintain records of the manufacturer's written operating and maintenance instructions. These records shall be retained for the life of the control equipment.
([~~c~~]3)The owner or operator shall keep and maintain records of the VOC control device AVO inspections. These shall be retained for a minimum of three years. These records shall include:

([~~i~~]a) the date of the inspection;
([~~ii~~]b) the status of the control device and associated equipment; and
([~~iii~~]c) date of corrective action taken, if applicable.

WEA Comment #18: The decision to use combined emissions from other source categories is problematic because it does not reflect a cost-benefit analysis for dehydrator units themselves. As a matter of policy, best available control technology (BACT) should reflect the economic and environmental impacts of the specific emissions unit. We also request UDAQ clarify whether the 4 tons per year of VOC emissions listed refers to controlled or uncontrolled emissions.

DAQ Response: DAQ disagrees with this comment. Economic feasibility is determined on a cost per ton removed basis. If a single control device can control emissions from two different sources, a cost-benefit analysis for a single piece of equipment is incomplete. See response to WEA Comment #4. No changes were made as a result of this comment.

WEA Comment #19: For VOC control devices, we recommend a minor clarification that the requirements apply only if control devices are required due to the rule provisions.

DAQ Response: DAQ disagrees with this comment. The requirements of this provision ensure that the combustor meets the appropriate control efficiency, is operated and maintained according to the specifications from the manufacturer, and lastly requires an AVO inspection monthly to verify the equipment is working. Any source that operates a control device should be performing these activities already because merely having a control device on site but not verifying that it is operating or operating correctly does not control emissions. No changes were made as a result of this comment.

WEA Comment #20: We request that UDAQ clarify within R307-509-4 that any operator fully compliant with 40 CFR § 60.5397a, or OOOOa fugitive emissions monitoring requirements, shall be deemed fully compliant with the requirements of UDAQ's LDAR program.

DAQ Response: DAQ agrees with this comment. R307-509-4 was derived from the requirements within 40 CFR 60 Subpart OOOOa, and our intent is to have the state rule mirror that of the federal subpart. An applicability clarification has been added in R307-509-3 to address this issue. However, the requirements in R307-509-4 will not be modified as these requirements may apply to sources when the federal subpart does not.

(a) A source meeting the requirements of 40 CFR 60.5397a is meeting the requirements of this rule.

WEA Comment #21: We also request that UDAQ make several clarifying changes to the recordkeeping requirements. To begin, there is no specified record retention period. We recommended this be amended to three years. We also recommend UDAQ clarify emissions monitoring plans be field-wide, or at a minimum production unit-wide. Given the similarity among many sites, site-specific monitoring plans are unnecessary and will add cost without commensurate environmental benefit.

DAQ Response: DAQ agrees with the need for clarification on record retention times and monitoring plan applicability. In regard to the monitoring plans level of resolution, the DAQ believes it is important to retain monitoring plans for each individual well site. Given the similarity among well sites, many of these monitoring plans will be identical. However, given the length of time wells remain in operation and the frequency at which they change owner's well sites within the same production unit or field may have differences in equipment types on site and therefore will require a different monitoring plan. R307-509-4 and R307-509-5 have been amended to clarify these issues.

(a) The owner[~~/~~]or operator shall develop an emissions monitoring plan that [~~will~~]shall be available upon request to review for each individual well site.

(1) The owner[~~/~~]or operator shall maintain records of the emissions monitoring plan[~~,~~].These records shall be retained for the life of the well site.
(2) The owner or operator shall maintain records of the monitoring surveys, repairs, and resurveys. These records shall be retained for a minimum of three years.

WEA Comment #22: EPA determined 30 calendar days to repair is an appropriate balance of environmental protection with practical considerations, and we believe the same balance should apply here. We also note that the terms "difficult-to-monitor" and "unsafe-to-monitor" are not defined in the proposed rules. We suggest that UDAQ simply reference the NSPS Subpart OOOOa definitions of these terms.

DAQ Response: DAQ will remain consistent with the current permitting practice of allowing 15 calendar days to repair leaks. The intent of these rules was to mimic the requirements applicable to the sources applying for permits. DAQ recognizes that the proposed state rule has a more stringent timeline than Subpart OOOOa, but it shall remain so. DAQ agrees with the need to define the terms "difficult to monitor" and "unsafe-to-monitor" and agrees that the definitions within NSPS Subpart OOOOa will suffice. Those definitions have been added to R307-509-2.

"Difficult-to-Monitor" means difficult-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.
"Unsafe-to-Monitor" means unsafe-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

WEA Comment #23: We do not believe that 180 days is an adequate period of time for operators to develop the documentation necessary to comply with the regulation, secure the resources and equipment needed to conduct the IR camera inspections and capture the necessary information, and to then test the tools in the field. For any existing facility that may be subject to the regulation we request an initial compliance date of January 1, 2019.

DAQ Response: DAQ agrees with this comment. A delayed effective date has been added to R307-509-4(1)(d)(i) to respond to this concern.

(i) No later than [180]365 days after January 1, 2018, or no later than 60 days after startup of production, as defined in 40 CFR 60 Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, whichever is later.

WEA Comment #24: We recommend that UDAQ to rely upon the existing NSPS regulations and hinge compliance on the different emission limits based on engine manufacture date, fuel type, and horsepower. That would provide the significant benefit of consistent federal and state regulation of engines. Alternatively, given operators' experience in Colorado with the Regulation 7 requirements, we believe that with the appropriate modifications for the construction or relocation date, it would be a manageable solution for industry while providing UDAQ with engine requirements that are protective of the environment.

DAQ Response: DAQ agrees. The intent of this rule was to rely upon the existing NSPS regulations and to mimic the requirements of BACT on sources applying for permits. DAQ has not allowed older engines to be permitted on new sites, or for any engine modifications at a well site, to include engines that do not meet the current NSPS regulations. R307-510 has been amended to correct this issue.

(1) Regardless of construction, reconstruction, or modification date, each stationary engine at a well site shall comply with the emission standards listed in Table 1 when the engine is installed, relocated, or modified.[~~40 CFR Subpart JJJJ when the engine is installed or modified.~~]

Table 1

Maximum Engine hp	*Emission Standards in (g/hp-hr)*			
	NOx	*CO*	*VOC*	*HC+NOx*
≥25 hp and < 100 hp	*-*	*4.85*	*-*	*2.83*
≥100 hp	*1.0*	*2.0*	*0.7*	*-*

(2) The owner or operator shall either:
(a) purchase a certified stationary internal combustion engine as defined in 40 CFR 60.4248, or
(b) conduct an initial performance test according to 40 CFR 60.4244.

Utah Petroleum Association (UPA) Comments
Questions and comments excerpted from original document.

UPA Comment #1: Existing facilities with throughput greater than 8,000 bbls of crude oil and emissions greater than 4 tons per year of VOC would be subject to the requirements of R307-506 and hence also would require control of loadout emissions per R307-504. This creates confusion with facilities who have voluntarily controlled emissions to ensure they are an exempt small source. We encourage the Division to clarify that existing sources are exempt from the requirements of R307-504.

DAQ Response: DAQ agrees that some sources that are currently controlling tank emissions will be required to control loadout emissions. See WEA Comments #1 and #3. No changes were made to the rules as a result of this comment.

UPA Comment #2: We are concerned that an existing source with throughput greater than 8,000 bbls of crude oil per year and actual emissions of less than 5 tons per year VOC that currently qualifies for the small source exemption would be subject to the requirements of the proposed rules if uncontrolled emissions exceed 4 tons per year VOC. This apparent elimination of the small source exemption for certain oil and gas facilities singles out these facilities as the only sources in Utah not afforded the ability to claim this important exemption. We suggest that UDAQ amend the language in R307-506-4 to state that facilities with actual emissions less than 4 tons per year of VOC are exempt from the regulations requirements.

DAQ Response: See response to WEA Comments #1 and #3. No changes were made to the rules as a result of this comment.

UPA Comment #3: We are concerned the proposed rules significantly expand the recordkeeping and reporting requirements of Utah oil and gas operators. We believe the Division has not fully evaluated all the costs or their impacts to Utah businesses.

DAQ Response: DAQ disagrees with this comment. The rules do not require any additional recordkeeping that sources with approval orders are not already doing. The purpose of the required recordkeeping is to show compliance with federal and state requirements. No changes were made to the rules as a result of this comment.

UPA Comment #4: We request UDAQ clarify that this rulemaking only applies the required BACT analysis to state lands. We understand UDAQ's preference that state and federal regulatory requirements be harmonized, but such rules affecting federal and tribal lands would require a detailed analysis of factors unique to those lands.

DAQ Response: DAQ only has primacy on state lands and as such these rules will only apply to sources on these lands, which are within the state's jurisdiction.

UPA Comment #5: As there is no apparent environmental benefit to the dual collection requirement, we recommend that UDAQ either exempt existing sites that report to the 2017 emissions inventory from reporting equipment and emissions data under the registration, or that the registration emissions data satisfy the 2017 inventory requirements.

DAQ Response: Refer to the response to WEA comment #5.

UPA Comment #6: We suggest that the per site fee for existing sources be dramatically reduced. The amount should be commensurate with the actual cost of regulation. We also suggest that UDAQ consider delaying fee implementation for a year to allow companies to properly budget for the regulatory expense.

DAQ Response: To accommodate the cost of software development, support, maintenance and ongoing management of the registration process the current registration fee for small sources and minor source permit filing fees are suitable. As stated in the response to WEA comment #8, existing sources will have approximately six months after the promulgation of these rules to register with DAQ and will be invoiced after registration.

UPA Comment #7: We believe the truck loading provisions of R307-504 do not appear to align with UDAQ's statement that it does not intend to require retrofit at existing locations that have been in compliance with current regulation and request that they be modified.

DAQ Response: DAQ disagrees with this comment. See WEA comment #3 and UPA comment #1. No changes were made to the rules as a result of this comment.

UPA Comment #8: The emission threshold in R307-506-4(2)(b) should be revised to indicate whether the threshold of 4 tons per year of VOCs refers to actual emissions after controls or uncontrolled emissions. We believe the threshold should be set at controlled emissions; since the operator already would have invested significant resources in controlling emissions, additional controls likely would not be cost effective.

DAQ Response: DAQ has amended R307-506-4(2)(b) to clarify the intent and correct the language to account for four tons of uncontrolled emissions. See WEA comment #13.

UPA Comment #9: We believe a more prudent course would be simply to specify that any application based on AP-42 emission factors could be used. As written, this provision is needlessly prescriptive and would create unnecessary compliance issues with no environmental benefit.

DAQ Response: DAQ agrees with this comment. R304-506-4 has been amended to include any calculation methodology that is based on AP-42 Chapter 7. See WEA comment # 13.

UPA Comment #10: We're concerned by UDAQ's approach to determining applicability for dehydrator emissions. The decision to use combined emissions from other source categories is problematic because it does not reflect a cost-benefit analysis for dehydrator units themselves. As a matter of policy, best available control technology (BACT) should reflect the economic and environmental impacts of the specific emissions unit. We also request UDAQ clarify whether the 4 tons per year of VOC emissions listed refers to controlled or uncontrolled emissions.

DAQ Response: DAQ disagrees with this comment. See WEA comment #4. DAQ has also amended R307-507-4(1) to clarify that controls are required on uncontrolled emissions. See WEA comment # 13.

(1) Dehydrators with VOC emissions of four tons of uncontrolled emissions per year or greater either individually or combined with VOC emissions from storage vessels shall either be routed to a process unit where the emissions are recycled, incorporated into a product, and/or recovered, or be routed to a VOC control device that is in compliance with R307-508. Dehydrators in operation before January 1, 2018, shall determine applicability with calculated actual emissions. Dehydrators in operation on or after January 1, 2018, shall determine applicability using potential to emit.

UPA Comment #11: For VOC control devices, we recommend a minor clarification that the requirements apply only if control devices are required due to the rule provisions. This small change would clarify that if an operator falls below the control threshold, it need not remove a control device to remain exempt from the PBR. Should an operator choose to voluntarily leave controls in place, but can demonstrate it is below the applicability threshold of the R307-500 series, it should not be subject to the full requirements by virtue of voluntarily leaving controls in place.

DAQ Response: DAQ disagrees with this comment. See WEA comment #19. No changes were made as a result of this comment.

UPA Comment #12: We are concerned the natural gas engine requirements in the proposed rules will be a significant source of confusion for industry. The engine requirements of R307-510-3(1) specify that engines shall comply with 40 CFR Subpart JJJJ, which opens the door to possible confusion when interpreting UDAQ's intent. Subpart JJJJ contains several different emission limits based on engine manufacture date, fuel type, and horsepower.

DAQ Response: DAQ agrees with this comment. R307-510 has been amended to clarify the intent and simplify compliance. See WEA comment #24.

EPA Comments/Clarifying Questions
Questions and comments excerpted from original document.

EPA Comment #1. In the memorandum and in the proposed rule text, it is unclear whether the permit by rule (PBR) would apply to just "well sites, as defined in 40 CFR 60.5430a" or also "well production facility," "oil and gas production sources," "oil and gas sources," "oil and gas wells," "oil and gas tank batteries," "oil and gas operations" and "oil and gas well sites" (all of the latter terms are used in various places in the proposed rule revisions and proposed new rules, but are not defined). For Storage Vessels/Dehydrators/Leak Detection and Repair (LDAR) the proposed text points to applicability of such equipment "associated with" or "at oil & gas operations" and specific sections appear to apply just to such equipment at "well sites." At the bottom of page 2 of the memorandum, the UDAQ states, "In summary, the proposed rule changes should provide a streamlined permitting process for minor oil and gas sources." The proposed new emissions inventory requirement at R307-150-9 is titled for the "Crude Oil and Natural Gas Source Category,"

while sections R307-504, 505, 506, 507, 508, 509 and 510 are titled for the "Oil and Gas Industry." Is the intent to refer to the same sector/segment for these rule sections? The EPA recommends using defined, consistent and clear terminology, as it is currently unclear which sources are covered by the various proposed rule revisions and proposed new rules.

DAQ Response: It is the Division's intent to have the broader range of oil and gas sources be subject to the inventory rule (R307-150-9) and the registration requirement (R307-505) and the PBR to be applicable to the more specific source of "well sites, as defined in 40 CFR 60.5430a." Changes have been made to the final version for adoption to make terms more consistent and clear.

EPA Comment #2. If the PBR just applies to "well sites, as defined in 40 CFR 60.5430a," then storage vessels/dehydrators/LDAR at other types of oil & gas production operations (e.g. centralized tank batteries , compressor stations, produced water underground injection control or evaporation pond disposal facilities) may not be required to meet the requirements. Would those types of operations need to apply BACT through a source- specific approval order?

DAQ Response: The PBR is intended to apply to "well sites, as defined in 40 CFR 60.5430a" and centralized tank batteries (the applicability sections have been revised to be more clear). All other types of oil and gas operations will need to apply for an approval order in accordance with R307-401.

EPA Comment #3. The memorandum to the AQB (page 2,2nd paragraph) states, "Those that have placed voluntary controls to become exempted small source (<5 TPY) may fall under the proposed rules for registration and inspection, but most likely will not be required to retrofit with new equipment if they appropriately applied the small source exemption." Does this mean that sources that installed a combustor, for example, to control storage vessel emissions that then resulted in emissions < 5 tpy and applied the small source exemption (Section R307-401-10) properly by submitting a registration claiming the exemption , would not need to perform monitoring, recordkeeping and reporting to assure compliance and performance of the control device? Are the General Requirements in R307-401-4 the provision that ensures proper operation of voluntary controls at such sources?

DAQ Response: The intent of the cited portion of the memorandum to the Air Quality Board was to state that "retrofitting'" of equipment would not be likely for those who placed voluntary controls to become a small source exemption, not that the source would be exempt from the proposed rules. If a source is required to control emissions on a tank or tank battery in accordance with R307-506, Storage Vessels, and does not have an air approval order, it will be subject to the monitoring, recordkeeping, and reporting requirements of R307-509, Leak Detection and Repair Requirements (LDAR).

EPA Comment #4. Section R307-401 states in the definition of "best available control technology" for approval order requirements that "In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61."The proposed source category exemption would require a minor oil and natural gas source to register per R307-505 instead of obtaining an approval order. As part of that registration, the source would have to comply with R307-506 through R307-510. None of those requirements propose control of pneumatic pumps. NSPS OOOOa (which EPA is currently reconsidering parts of) requires that pneumatic pumps be routed to a control device if one is required to be installed onsite already (see 40 CFR 60.6593a). We also note that the UDAQ's General Approval Order: Crude Oil and Natural Gas Well Site and/or Tank Battery also requires control of pneumatic pumps at sites with combustion units installed for the control of flash or dehydration unit emissions. Does the UDAQ intend to require control of pneumatic pumps in its PBR?

DAQ Response: In evaluating the 2014 emission inventory for oil and gas, pneumatic pumps were an extremely small contributor to VOC emissions. Existing sources that were required to obtain an air approval order would have evaluated the pneumatic pumps and appropriately applied BACT. Currently no oil and gas sources are regulated by the general approval order. As sources with pneumatic pumps are currently required to meet OOOOa of 40 CFR part 60, they are meeting BACT. It was determined not to address pneumatic pumps at this time.

EPA Comment #5. In proposed Section R307-508 for VOC control devices, how is the requirement that the device be certified by the manufacturer enforceable? There does not appear to be a certification program similar to the demonstration of compliance requirements in NSPS 0000/a. NSPS 0000/a requires performance testing of control devices. To ease the burden on operators of field testing control devices, NSPS OOOOa at 60.5413a(b) exempts operators from conducting performance tests of the control device if they install a model by a manufacturer who has conducted the performance testing in 60.5413a(d). The EPA suggests revising the proposed section to provide specifications for certification of a VOC control device.

DAQ Response: DAQ has made corrections to R307-508-3 to include demonstration of compliance with a 95% control efficiency by meeting the performance test methods and procedures specified in 40 CFR 60 Subpart OOOOa.

(1) A VOC control device required by R307-506 or R307-507 must have a control efficiency of 95% or greater.

(a) The VOC control device shall operate with no visible emissions.

(b) The VOC control device must comply with R307-503.

(2) [~~To show compliance with the control efficiency, the VOC control device shall be operated according to the manufacturer's specifications and be certified by the manufacturer to reduce VOC emissions by 95% or greater.~~] A well site shall demonstrate compliance by meeting the performance test methods and procedures specified in 40 CFR 60.5413.

EPA Comment #6. The proposed requirements for storage vessels and dehydrators (R307-506 and 507) provides for the removal of controls when actual emissions of the collection of storage vessels and dehydrators are less than 4 tpy on a rolling twelve-month basis. Assuming a control device achieves 95% control efficiency, if the control device is removed from a source with such actual VOC emissions just under 4 tpy (accounting for the control device), the actual emissions would increase to just under 80 tpy upon removal of the control device, which is significantly above 4 tpy, the emissions trigger in the proposed requirements to install a control device at an existing or new source. The EPA suggests revising the proposed provision to allow control device removal if uncontrolled actual VOC emissions are less than 4 tpy.

DAQ Response: DAQ agrees there was some confusion on when a control device could be removed. R307-506 and R307-507 have been amended to clarify that emissions are based on uncontrolled emission. See WEA comment #13 and UPA comment #10.

EPA Comment #7. Section R307-506 for storage vessels proposes to require that an "owner or operator that is required to control emissions in accordance with R307-506-4(2) and R307-506-4(3) shall inspect at least once a month each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c)." EPA recommends a similar provision be proposed for an owner or operator that is required to control dehydrator emissions in Section R307-507 for dehydrators. The National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities at 40 CFR

part 63, Subpart HH, which contains control requirements for dehydrators, contains closed-vent system and no detectable emissions requirements similar to those in NSPS OOOOa for storage vessels .

DAQ Response: DAQ agrees with this comment, the owner or operator would be required to inspect each closed vent system monthly as a BACT requirement through the permitting process. R307-507 has been amended to include the requirement for monthly inspections as well as the appropriate recordkeeping.

R307-150-9

EPA Clarifying Question #1: Will the UDAQ continue to account for estimates of formaldehyde and other HAP emissions, as in other sections ofR307-150?

DAQ Response: DAQ will only account for estimates of formaldehyde from engines. This is the only crude oil and natural gas source category equipment type with available AP-42 emission factors. DAQ is not aware of any emission calculation methods available for estimating formaldehyde or hazardous air pollutant emissions from other crude oil and natural gas source category equipment types.

R307-401

EPA Clarifying Question #2: Per 60.5430a "well site," for the purposes of fugitive emissions standards ... "also means a separate tank battery surface site collecting crude oil, condensate ... or produced water from wells not located at the wellsite (e.g. centralized tank batteries)." Does the proposed Permit by Rule (PBR) also cover centralized tank batteries, produced water disposal wells or evaporation ponds, or midstream compressor stations? If not, then will these non- "well site" type sources be required to apply BACT via an approval order?

DAQ response: The PBR is intended to apply to "well sites, as defined in 40 CFR 60.5430a" and centralized tank batteries (the applicability sections have been revised to be clearer). All other types of oil and gas operations will need to apply for an approval order in accordance with R307-401.

R307-504-1

EPA Clarifying Question #3: The terms "well production facility" vs. "well site" vs "tank battery" are used in various places. Are tank truck loading/unloading operations at centralized tank batteries covered here?

DAQ Response: The intent is to have all well sites, which is defined in R307-401, to include centralized tank batteries. Truck loading/unloading operations will apply to that are required to control emissions from storage vessels. So if the source is required to control emissions from their well site, they will then be required to control truck loading/unloading emissions.

EPA Clarifying Question #3: It is unclear if the submerged fill and bottom filling requirements refer to things required for the tank truck versus the storage vessel. "Tanker trucks," "tank trucks" and "tanks" appear to be used interchangeably. The EPA suggests using consistent and clear terminology for example, either "tank truck" or "tanker truck" consistently.

DAQ Response: DAQ agrees and has amended R307-504 to correct inconsistent language. "Tanker truck" is the terminology being used going forward.

R307-504-4

(1) <u>Tanker</u> trucks used for intermediate hydrocarbon liquid or produced water shall be loaded using bottom filling or a submerged fill pipe.

<u>R307-504-4</u>

EPA Clarifying Question: #5: It is unclear how the 70% capture efficiency would be verified and enforced (and therefore the 68.6% control efficiency)? R307-506-4 provides that the storage vessel thief hatch does not need to remain closed and latched during vessel unloading, which stands to reason that vapors could escape through the thief hatch during unloading. Is this accounted for in the 70% capture efficiency calculation? There is no requirement related to auto-ignitors in R307-508 VOC Control Devices. What is the basis for 3% control efficiency assumption attributed to an auto ignitor?

DAQ Response: The 70% capture efficiency came from AP-4.2 Chapter 5.2; upon further review, the 70% capture efficiency is assumed by default and as such not enforceable. It has been removed from the rule, as well as the language pertaining to an auto ignitor. The definition of a “Vapor Capture Line” has been amended to capture the intent of the 70% capture efficiency. See WEA comment #12.

<u>R307-505</u>

EPA Clarifying Question #6: "well production facility"vs. "well sites" ... Does this include centralized tank batteries , compressor stations, natural gas processing plans , or produced water treatment/disposal facilities? If the disposal well is not "commercial," then is it covered? What is meant by "commercial"? EPA suggests using consistent, defined terminology to avoid confusion.

DAQ Response: Well site definition has been clarified.

<u>R307-506-1</u>

EPA Clarifying Questions #7: "Oil and gas operations" is not a defined term. Does this section just apply to storage vessels at "well sites"? (See R307-506-3(1)) . Does this mean that storage vessels at centralized tank batteries , natural gas processing plants, produced water treatment/disposal facilities or compressor stations, for example, would require application of BACT via an approval order?

DAQ Response: This rule is for storage vessels at well sites, to include centralized tank batteries, as stated in the applicability section. This has been clarified in the final version of the rule presented for adoption.

<u>R307-506-3</u>

EPA Clarifying Question #8: Would storage vessels at centralized tank batteries , compressor stations, natural gas processing plants or produced water treatment/disposal facilities require application of BACT via an approval order or general approval order?

DAQ response: The PBR is intended to apply to "well sites, as defined in 40 CFR 60.5430a" and centralized tank batteries (the applicability sections have been revised to be clearer). All other types of oil and gas operations will need to apply for an approval order in accordance with R307-401.

<u>R307-506-4</u>

EPA Clarifying Question #9: "other maintenance activities" is not defined -what types of activities are included in this general term? Is an open and unlatched thief hatch during loading of a tank truck accounted for in the 70% capture efficiency requirement for section R307-504-4(2)?

DAQ Response: The 70% capture efficiency was removed from the rule as it was not enforceable. See EPA Clarifying Question: #5.

EPA Clarifying Question #10: The definition of "storage vessel" in NSPS OOOOa (under reconsideration) includes vessels that store crude oil, condensate, and produced water. Paragraph (2) of this section discusses only "crude oil" throughput for applicability of the requirements. Is this section intended to cover emissions from condensate and produced water storage vessels as well?

DAQ Response: DAQ has clarified the rule to include condensate in addition to the crude oil that was previously mentioned. The crude oil and condensate throughput is used to determine if a control device is required, if a control device is required by rule, then all "storage vessels" as defined in NSPS OOOOa will need to be controlled.

EPA Clarifying Question #11: Does "collection of storage vessels" refer only to any series of individual storage vessels that are manifolded together, or to the accumulation of all storage vessels at a "well site"?

DAQ Response: The intent of this rule was to require that the storage vessels that are applicable to the rule (all storage vessels except "emergency storage vessels") need to be controlled if triggered by the oil or condensate throughput listed. In order to avoid defining what a "collection of storage vessels" meant, we have removed the language and amended the rule to account for "all storage vessels located at the well site."

EPA Clarifying Question #12: NSPS OOOOa provides for the removal of a control device after 12 consecutive months of operating a control device when the "uncontrolled actual VOC emissions" (emphasis added) of a storage vessel are less than 4 tpy. (See 40 CFR 60.5395a(a)(3)). Assuming a control device achieves 95% control efficiency, if the control device for a storage vessel with actual VOC emissions just under 4 tpy (accounting for the control device) is removed, the actual emissions would increase to just under 80 tpy, which is significantly above 6 tpy, the potential emissions trigger in NSPS OOOOa for installing a control device. The EPA suggests revising the proposed provision as indicated above.

DAQ Response: The rule was ambiguous and has been amended to include the appropriate terminology of "uncontrolled VOC emissions."

EPA Clarifying Question #13: Would all "crude oil" storage vessels be required to be controlled upon start-up, regardless of throughput and then the throughput evaluated after a year of operation to determine if actual emissions of VOC < 4 tpy and controls can be removed, or just storage vessels with throughput of 8,000 barrels of "crude oil" in any 12-month period?

DAQ Response: R307-506-4(6), now R307-506(7), has been amended to correct the ambiguity caused by using a rolling twelve-month basis and one year of operation.

([~~6~~]7) After a minimum of one year of operation, controls may be removed if [~~when~~] site-wide throughput is less than 8,000 barrels of crude oil or 2,000 barrels of condensate on a rolling [~~twelve-~~]12-month basis or uncontrolled actual emissions are demonstrated to be less than four tons per year.[~~after one year of operation.~~]

EPA Clarifying Question #14: How was 8,000 barrels over a 12-month rolling basis derived as surrogate for a VOC emissions threshold? We recommend that UDAQ consider the example that 80% of VOC emissions from a 5 tpy site is from storage vessels (i.e., 4 tpy, which also the same as the NSPS 0000/0000a (under reconsideration) threshold for tank control removal) -that would equate to an emission factor of only 1.0 lbs VOC/barrel of crude oil or condensate. In the 2014 Uinta Basin Emissions Inventory, oil tank median tank emission factors for each operator ranged from 0.04 to 7.94lbs VOC/barrel. The Colorado Department of Public Health and Environment default crude oil emission factor for crude oil tanks is 3.2 lb VOC/barrel. For condensate those numbers range from 0.27 to 10.99lb VOC/barrel. EPA's Control Techniques Guidelines for the oil and natural gas sector in ozone nonattainment areas, has an LDAR threshold of 15 BOED (8,000 barrels oil/yr = 22 bbl/day and does not account for associated gas production that would be included in BOED). LDAR in section R307-509links to whether the well site is subject to the requirements to control storage vessel or dehydrator emissions. There is no guarantee that being < 8,000 barrels/yr will equate to < 4 tpy VOC in the control removal thresholds.

DAQ Response: DAQ has determined that the threshold for controls required as BACT for storage vessels is four tons of VOC emissions. Using EPA Tanks 4.0.9d and the Vasquez Beggs Equation, paired with common values reported from crude oil samples resulted in a throughput of roughly 8,000 barrels per year. Given the many different methodologies that exist for calculating emissions from crude oil there are likely to be sites that exceed 8,000 barrels and are above four tons per year, just as likely as there are sites that will be below four tons. A throughput, rather than an emissions limit, was chosen in part because there are so many different methods of calculating emissions that compliance determinations would have been difficult and also somewhat arbitrary depending on which method was used. Given what we know, this was a compromise that will result in a streamlined approach for compliance as well as a method for easing the compliance burden for operators, as they will not need to calculate emissions for every well site. DAQ acknowledges that there is no guarantee that being <8,000 barrels per year will result in less than four tons per year of VOC emissions, but as our requirement is on all storage vessels combined, rather than on an individual basis, we are still more stringent than the requirements of 40 CFR Subpart OOOOa.

EPA Clarifying Question #15: Per NSPS OOOOa (under reconsideration) at 40 CFR 60.5411a(c)(l), the closed vent system is to be designed to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device. §60.5411a(d)(l) requires sufficient design and capacity of CVS certified by professional engineer. The EPA suggests revising the proposed provision as indicated above.

DAQ Response: Given that NSPS OOOOa is under review, in particular the need for a control device to be certified by a professional engineer, DAQ has decided it would not be in our best interest to adopt this language. However, given the LDAR requirements of R307-509, if the closed vent is inadequately designed, the operator will have trouble passing a leak detection test and will need to make the appropriate changes to their system to correct the issue. No changes were made as a result of this comment.

EPA Clarifying Question #16: TANKS 4.09D is EPA's legacy computer model for estimating storage tank emissions per AP-42, Chapter 7. It only runs on Windows XP, and it has not been updated to reflect improvements to Chapter 7 and API guidance. EPA has posted a disclaimer on the CHIEF website that the TANKS software is outdated and that we no longer support it. EPA is not planning to update the software. EPA suggests removing any reference to TANKS 4.09D and instead to refer

to AP-42 Chapter 7, and include "any software program in use by industry" that is based on Chapter 7. Chapter 7 can apply to any above-ground atmospheric tank that does not have flash emissions.

The EPA in its direct implementation of NSR and Title V permitting in Indian country prefers, but does not require, that direct measurement, process simulator computer program (HYSIS, VMG, PROMAX, HYSIM, etc.), E&P TANKS or Lab Measurement of GOR be used rather than other available methods, like the Vasquez-Beggs Equation. We advise that applicants choosing a less accurate method may be risking potentially underestimating emissions at a source and, thus, potentially risking non-compliance if more accurate methods indicate emissions at major source levels. For this proposed regulation, if an operator finds that the emissions are greater than what was originally represented, must they revise their emissions to reflect the increase?
Regarding the Vasquez-Beggs Equation, another state program with permitting authority in areas with significant oil and gas development , the Texas Commission on Environmental Quality (TCEQ) states that The Vasquez-Beggs Equation variables must be supported with a lab sampling analysis that verifies the API gravity , separator gas gravity, stock tank gas molecular weight, and VOC fraction. If an operating variable used in the Vasquez-Beggs Equation calculations falls outside of the parameter limits, the applicant must use another method to calculate flash emissions. 1 The TCEQ requires operators to verify that all inputs are in valid ranges (see Table below). Some variables may be adjusted so that the Vasquez-Beggs Equation can be used; other variables cannot be adjusted. See "Explanation" section of the table to determine which variables are critical. If a variable is outside of the acceptable range, and no adjustments can be made, the Vasquez-Beggs Equation cannot be used. For example, the Vasquez-Beggs Equation could not be used for condensate production because API gravity> 40°.

DAQ Response: The rule has been amended to incorporate any emissions calculation methodology that is based upon AP-42 Chapter 7 and a site specific sample. See WEA comment #13.

EPA Clarifying Question #17: NSPS OOOOa (under reconsideration) at 60.54lla(B)(l) states "...the cover and all openings on the cover (e.g. access hatches, sampling ports, pressure relief devices and gauge wells) ..." The EPA suggests revising the proposed provision as indicated above.

DAQ Response: DAQ has used this language in all of our existing approval orders, and it is language that has been agreed upon through many hours with the operators. Given the understanding our compliance inspectors have and that "closed vent system" is used and is defined in 40 CFR 65.2 no changes are necessary.

<u>R307-506-5</u>

EPA Clarifying Suggestion #18: The EPA suggests using a consistent description , i.e. "closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass devices" versus just "thief hatch."

DAQ Response: DAQ agrees with this comment. Changes have been made to R307-506-5 to correct this inconsistency.

(1) Records of each [~~thief hatch~~] <u>closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device</u> [~~inspection~~] shall be kept for three years.
(a) Records of <u>each</u> [~~thief hatch~~] <u>closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device</u>[~~inspection~~] shall include the date of the inspection, the

status of [~~the~~]each [~~thief hatch~~] closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass device, and the date of corrective action taken if required.

EPA Clarifying Suggestion #19: The EPA suggests including a requirement to keep records of API or US well ID numbers associated with each well site to easily verify the production rate of a well site and information on well site modifications.

DAQ Response: Utah Division of Oil, Gas, and Mining requires this information be posted or readily at every well site. Given this requirement, DAQ has not added any duplicative requirements.

R307-507-3

EPA Clarifying Question #20:"Oil and gas operations" is not a defined term. Does this section just apply to dehydrators at "well sites"? (See R307-507-3(1)). Does this mean that dehydrators at natural gas processing plants or compressor stations would require application of BACT via an approval order?

DAQ Response: This rule is for dehydrators at well sites, to include centralized tank batteries, as stated in the applicability section. This has been clarified in the final version of the rule presented for adoption.

R307-507-5

EPA Clarifying Suggestion #21: Assuming a control device achieves 95% control efficiency, if the control device is removed from a dehydrator with actual VOC emissions just under 4 tpy (accounting for the control device), the actual emissions would increase to just under 80 tpy, which is significantly above 4 tpy, the emissions trigger in this section for the requirements to install a control device on existing or new dehydrators. The EPA suggests revising the proposed provision as indicated above.

DAQ Response: DAQ has corrected this issue as our intent for removal involved uncontrolled emissions. R307-507-4(2) has been amended and "uncontrolled" has been added for clarification.

EPA Clarifying Suggestion #22: Section R307-506 proposes to require that an "owner or operator that is required to control emissions in accordance with R307-506-4(2) and R307-506-4(3) shall inspect at least once a month each closed vent system , including vessel openings , thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c)." EPA suggests a similar provision be proposed for an owner or operator that is required to control dehydrator emissions. The National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities at 40 CFR part 63, Subpart HH, which contains control requirements for dehydrators , contains closed- vent system and no detectable emissions requirements similar to those in NSPS OOOOa.

DAQ Response: DAQ agrees with this comment. Our intent was to develop rules that were in accordance with BACT determinations made during the approval order process, and we overlooked this issue. R307-507-4 has been amended to require a monthly inspection of each closed vent system, as well as the associated recordkeeping in R307-507-5

(2) An owner or operator that is required to control emissions in accordance with R307-507-4(1) shall inspect, at least once a month, each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.
(3) Modification to a well site shall require a re-evaluation of emissions in accordance with R307-507-4(1). (insert language from final version of rule)

R307-508

EPA Clarifying Question #23: Does this section apply to VOC control devices at any "oil and gas operation" (not defined) or just at "well sites"?

DAQ Response: This rule is for VOC control devices at well sites, to include centralized tank batteries, as stated in the applicability section. This has been clarified in the final version of the rule presented for adoption.

EPA Clarifying Question #24: How is the requirement that the device be certified by the manufacturer enforceable? There does not appear to be a certification program similar to the demonstration of compliance requirements in NSPS 0000/a. NSPS 0000/a requires performance testing of control devices. To ease the burden on operators of field testing control devices, NSPS OOOOa at 60.5413a(b) exempts operators from conducting performance tests of the control device if they install a model by a manufacturer who has conducted the performance testing in 60.5413a(d). The EPA suggests making the revision indicated above to paragraph (2).

DAQ Response: DAQ has corrected this issue to improved compliance determination. See EPA comment #5.

EPA Clarifying Question #25: Would these requirements be imposed in addition to the auto-ignitor required at R307- 503, or is an auto ignitor not required for VOC control devices used to comply with R307-506 and 507? Must a pilot flame be present at all times? Are visible emissions allowed?

DAQ Response: DAQ has clarified that the VOC control device must comply with the requirements of R307-503, as well as operate with no visible emissions. This was overlooked, and is a common requirement during the approval order process. R307-508-3 has been amended as a result of this comment.

(b) The VOC control device must comply with R307-503.

R307-509

EPA Clarifying Question #26:"Oil and gas operations" is not a defined term. Does this section just apply to fugitive emissions components at "well sites"? (See R307-509-3(1)). Does this mean that fugitive emissions components at natural gas processing plants or compressor stations would require application of BACT via an approval order or general approval order?

DAQ Response: This rule is for LDAR at well sites, to include centralized tank batteries, as stated in the applicability section. This has been clarified in the final version of the rule presented for adoption.

R307-510

EPA Clarifying Question #27:"Oil and gas operations" is not a defined term. Does this section just apply to natural gas- fired engines at "well sites"? (See R307-510-2(1)). Does this mean that engines at natural gas processing plants or compressor stations would require application of BACT via an approval order or general approval order?

DAQ Response: This rule is for engines at well sites, to include centralized tank batteries, as stated in the applicability section. This has been clarified in the final version of the rule presented for adoption.

EPA Clarifying Question #27: Would this section apply to a facility existing before January 1, 2016 but without an approval order?

DAQ Response: No, this rule is applicable to sources that began operations after January 1, 2016, or installed new or modified engines after January 1, 2016.

EPA Clarifying Question #28: Are there any requirements for engines fired with any other fuel type (liquefied petroleum gas, gasoline, diesel, etc.)? What about spark ignition engines fired with other fuels that are not subject to NSPS JJJJ or diesel-fired engines that are not subject to NSPS IIII?

DAQ Response: DAQ has acknowledged that our current rules do not address engines that are fired by other means outside that of natural gas. Our intent is to develop rules in the future to address these fuel types, but the vast majority of the wells on state lands operate using field gas. The nuances of dealing with other fuel types is something we want to evaluate closer to ensure that the rules are all inclusive. Currently if an operator is using an engine that runs on an alternative fuel type, that source would be required to come in and obtain an approval order, until such a time that we can develop more inclusive rules.

Dominion Energy Comments
Questions and comments excerpted from original document.

Dominion Question #1: One significant comment is certain recordkeeping (e.g., emission calculations, repair records) should have defined time duration since many wells may produce for decades, for example. I suggested three years since three was mentioned within the other parts of the proposed regulations.

DAQ Response: DAQ has amended the recordkeeping requirements to clarify the retention periods. In most a three year retention period was used.

Dominion Question #2: Another significant comment is to remove the combined emission total for R307-506 Dehydrator. It seems inappropriate to add storage vessels to the R307-506 Dehydrator Requirements (e.g., emissions threshold of four tons per year). Suggest keeping the R307-506 Storage Vessels and R307-506 Dehydrator sources completely separate in their applicability to the proposed Rules.

DAQ Response: These two emission units at a source are controlled with the same control device and as such, on a cost per ton removal basis for VOC emissions, it does not make sense to separate these two equipment types. See WEA comment # 4. No changes were made to the rules as a result of this comment.

Dominion Question #3: R307-401-2 General suggestion: add well modification (or modified) to the Permit by Rule definitions. It does appear in the R307-506 Storage Vessels definitions.

DAQ Response: As a well is modified and it has a current air approval order it will be addressed through the permit modification process.

Dominion Question #4: R307-506-5 General suggestion: add condensate as another storage vessel content throughout the R307-506 Storage Vessel regulation, as applicable (i.e., crude oil and/or

condensate versus only crude oil). For many gas well producers, condensate is the more common terminology for the storage vessel's content.

DAQ Response: DAQ has amended R307-506-5 to accommodate emissions associated with condensate throughput. A new throughput value of 2,000 barrels was determined to correlate to four tons of VOC emissions.

Josh Hirschi Comments
Questions and comments excerpted from original document.

Hirschi Comment #1: If these measures weren't meant to help with wintertime ozone concentrations, then would that mean more controls and measures will be proposed to address the non-attainment designation? I assume that the oil and gas industry (instead of jointly with other industries) will bear the cost of these extra controls and measures when they may not be needed.

DAQ Response: The current rules mimic the requirements sources are currently complying with due to BACT determinations during the permitting process. This is being done to streamline the permitting process as well as ease the burden on industry caused by repeat modifications that have minimal if any increase in air emissions. If new rules requiring additional controls and measures are implemented, industry as well as residents would have the opportunity to comment and address concerns related to all issues, including costs.

Hirschi Comment #2: While I appreciate that UDAQ would like to better understand the oil and gas sources around the state, imposing a triennial emissions inventory in addition to registrations, and removing small source exemption options for sites seems to not be dissimilar to singling out one industry, since not all industries would be regulated equally.

DAQ Response: DAQ acknowledges that sources in the oil and gas sector will be required to register, something that is optional in the current small source registration rule. However, aside from the mandatory registration, the small source exemption still exists, and these rules will not affect sources whose emissions are below five tons per year.

Hirschi Comment #3: Also, UDAQ is effectively removing the small source exemption option with these rules, since oil and gas sites above and below the 5 tpy threshold established in R307-401-9 will need to register under these rules.

DAQ Response: DAQ is requiring the sources register, but the small source exemption rule is not being removed, as these rules won't require anything of small sources. The registration is an accounting and compliance tool. Without knowing what sources exist and where, determining compliance is difficult. For rural industries, in this case oil and gas, a mandatory registration is needed so the DAQ can determine compliance with state rules. See comment #2.

Hirschi Comment #4: Be more specific on the types of equipment that will need to be registered, or designate some kind of emissions threshold in order to decrease the burden on industry of registering sources which are not important to UDAQ.

DAQ Response: Due to the triennial inventory, the registration has been kept simple to ease the burden on industry, as a detailed account of equipment and operations will be included and updated every three years.

Hirschi Comment #5: In reference to condition R307-506-4(2)(b)(iii) VOC emissions determined by an alternative method approved by the Director, I propose that when other methods are approved

by the Director that they be approved on a state-wide basis rather than on an as-requested or by-company basis, in order to alleviate the burden on UDAQ and on various companies.

DAQ Response: DAQ has simplified R307-506-4 to account for any calculation methodology that is based upon AP-42 Chapter 7. This modification solves the problems that this question brings up.

Hirschi Comment #6: It is requested that the 15-day lead time be changed to allow 30 days for repair, which should give enough time to address access issues and alleviate shipping time concerns for when parts or experienced professionals or equipment are needed to address an issue.

DAQ Response: The intent of these rules was to mimic the requirements on sources that have been determined through the implementation of BACT during the permitting process. The 15-day time allotted for repair has been found to be acceptable for several years, and sources are not having difficulty complying with this requirement. At this time DAQ does not feel it necessary to change the allotted time for repairs.

Hirschi Comment #7: I would suggest that if these rules aren't meant to address the nonattainment designation nor meant to fix the air quality in the basin to bring it to within NAAQS attainment levels for ozone, that UDAQ establish the frequency as an annual inspection and review the topic as a possible measure/control in the future if UDAQ is forced to write additional measures/controls into a SIP.

DAQ Response: DAQ is implementing these rules to replace the need for a source to obtain an air approval order from DAQ. These rules will not bring in sources that were not required to obtain an approval order, and as such the impact on existing sources should be minimal. The requirement for semi-annual LDAR inspections is one that a federal subpart deems necessary as well as BACT determinations for sources that have obtained approval orders when the subpart was not applicable. Since these rules will replace the permitting process, the need to remain consistent with the current permitting BACT determinations, means no changes were made as a result of this comment.

<u>Nick Michaelson Questions</u>

Michaelson Question #1: Just as there can be multiple individual storage vessels at a site, it appears there can also be more than one "collection of storage vessels" at a site for purposes of R307-506-4(2), correct?
a. For example, many production sites in Utah dedicate one or more storage vessels to specific product streams or functions such as:
i. Crude Oil
ii. Condensate
iii. Produced Water
iv. Drain (slop oil) tanks
v. Emergency relief or blowdown tanks
b. Some tanks, such as those used for emergency relief or as a drain tank are not capable of being controlled for technical and/or safety reasons. It would appear appropriate then the 8,000 bbl of crude oil throughput or 4 tpy VOC thresholds would be evaluated for each tank service or purpose, agreed?

DAQ Response: DAQ has amended R307-506-4(2) to read "all storage vessels located at a well site." This will help clarify the throughput, as well as clarify the intent that all storage vessels should be controlled if a control device is on site. An exemption was added in R307-506-4-4 for emergency relief or blowdown tanks. With the addition of the exemption, additional recordkeeping requirements were incorporated to verify the tanks are being used appropriately.

Michaelson Question #2: For purposes of R307-506-4(3) – Storage vessels that begin operation after 1/1/2018 – there does not appear to be any distinction in the service or purpose of a "storage vessel". In which case, emergency relief tanks and drain tanks would be required to be controlled for the first year of operation?

DAQ Response: Drain tanks should be controlled as there is no technical reason they cannot be. An exemption has been included in R307-506-4-4 for emergency relief tanks.

Michaelson Question #3: The truck loading requirements of R307-504 are tied to the storage vessel requirements. With respect to new (post 1/1/2018 startup) storage vessels that require control for the first year of operation and question 2 above, are emergency relief and drain tank loading emissions required to be controlled for the first year of operation? If so, was this something envisioned during the rulemaking? a. Also along these lines, was there a technical evaluation or consideration of the ability to control emissions from non-oil tanks? Specifically, it would seem that the vent stream from non-oil truck loading (e.g. produced water) would contain primarily water vapor and trace amounts of gaseous hydrocarbons and thus low BTU contents, brining into question the ability of a control device to perform to its designed efficiency as there are typically lower thresholds for BTU content that control device manufacturers will guarantee.

DAQ Response: If a source is required to control VOC emissions from storage vessels, then the drain tank will need to be controlled; however, an exemption has been included for emergency relief tanks. The requirement to control emissions from all storage tanks as well as loading operations for all produced fluids is one that sources have been complying with for years. The BTU content from produced water is actually fairly high, and controlling these emissions is technically feasible.

Clean Air Coalition Comment:
The Utah State Digest published Oct 1, 2017 contained analysis of financial impacts of these rules. Three rules, R307-506 Storage Vessels, R307-508 VOC Control Devices, and R307-509 Leak Detection and Repair Requirements had potential compliance costs of $40,000 - $60,000 per source. This large potential cost was not part of the public discussion with the AQB in September.

These potential costs were calculated before the AQB meeting, I am informed, because the information is required for publication in our state digest.

As the costs are part of the requirement for proposing rules to public comment, this information should be provided to the AQB for their consideration when determining to propose a rule for public comment.

DAQ Response: DAQ agrees with the comment and will ensure costs are provided to Air Quality Board prior to the meeting when rules are proposed. As stated by the commenter, these costs were included in the State Bulletin, and are noted in the beginning of this document.

R307. Environmental Quality, Air Quality.

R307-150. Emission Inventories.

R307-150-1. Purpose and General Requirements.

(1) The purpose of R307-150 is:

(a) to establish by rule the time frame, pollutants, and information that sources must include in inventory submittals; and

(b) to establish consistent reporting requirements for stationary sources in Utah to determine whether sulfur dioxide emissions remain below the sulfur dioxide milestones established in the State Implementation Plan for Regional Haze, section XX.E.1.a, incorporated by reference in R307-110-28.

(2) The requirements of R307-150 replace any annual inventory reporting requirements in approval orders or operating permits issued prior to December 4, 2003.

(3) Emission inventories shall be submitted on or before ninety days following the effective date of this rule and thereafter on or before April 15 of each year following the calendar year for which an inventory is required. The inventory shall be submitted in a format specified by the Division of Air Quality following consultation with each source.

(4) The executive secretary may require at any time a full or partial year inventory upon reasonable notice to affected sources when it is determined that the inventory is necessary to develop a state implementation plan, to assess whether there is a threat to public health or safety or the environment, or to determine whether the source is in compliance with R307.

(5) Recordkeeping Requirements.

(a) Each owner or operator of a stationary source subject to this rule shall maintain a copy of the emission inventory submitted to the Division of Air Quality and records indicating how the information submitted in the inventory was determined, including any calculations, data, measurements, and estimates used. The records under R307-150-4 shall be kept for ten years. Other records shall be kept for a period of at least five years from the due date of each inventory.

(b) The owner or operator of the stationary source shall make these records available for inspection by any representative of the Division of Air Quality during normal business hours.

R307-150-2. Definitions.

The following additional definitions apply to R307-150.

"Acute pollutant" means any noncarcinogenic air pollutant for which a threshold limit value - ceiling (TLV-C) has been adopted by the American Conference of Governmental Industrial Hygienists in its "Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices," 2003 edition.

"Carcinogenic pollutant" means any air pollutant that is classified as a known human carcinogen (A1) or suspected human carcinogen (A2) by the American Conference of Governmental Industrial Hygienists in its "Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices," 2003 edition.

"Chronic Pollutant" means any noncarcinogenic air pollutant for which a threshold limit value - time weighted average (TLV-TWA) having no threshold limit value - ceiling (TLV-C) has been adopted by the American Conference of Governmental Industrial Hygienists in its "Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices," 2003 edition.

"Dioxins" and "Furans" mean total tetra- through octachlorinated dibenzo-p-dioxins and dibenzofurans.

"Emissions unit" means emissions unit as defined in R307-415-3.

"Large Major Source" means a major source that emits or has the potential to emit 2500 tons or more per year of oxides of sulfur, oxides of nitrogen, or carbon monoxide, or that emits or has the potential to emit 250 tons or more per year of PM[~~10~~]$_{10}$, PM[~~2.5~~]$_{2.5}$, volatile organic compounds, or ammonia.

"Lead" means elemental lead and the portion of its compounds measured as elemental lead.

"Major Source" means major source as defined in R307-415-3.

R307-150-3. Applicability.

(1) R307-150-4 applies to all stationary sources with actual emissions of 100 tons or more per year of sulfur dioxide in calendar year 2000 or any subsequent year unless exempted in (a) below. Sources subject to R307-150-4 may be subject to other sections of R307-150.

(a) A stationary source that meets the requirements of R307-150-3(1) that has permanently ceased operation is exempt from the requirements of R307-150-4 for all years during which the source did not operate at any time during the year.

(b) Except as provided in R307-150-3(1)(a), any source that meets the criteria of R307-150-3(1) and that emits less than 100 tons per year of sulfur dioxide in any subsequent year shall remain subject to the requirements of R307-150-4 until 2018 or until the first control period under the Western Backstop Sulfur Dioxide Trading Program as established in R307-250-12(1)(a), whichever is earlier.

(2) R307-150-5 applies to large major sources.

(3) R307-150-6 applies to:

(a) each major source that is not a large major source;

(b) each source with the potential to emit 5 tons or more per year of lead; and

(c) each source not included in R307-150-3(2), R307-150-3(3)(a), or R307-150-3(3)(b) that is located in Davis, Salt

Lake, Utah, or Weber Counties and that has the potential to emit 25 tons or more per year of any combination of oxides of nitrogen, oxides of sulfur and PM[~~10~~]$_{10}$, or the potential to emit 10 tons or more per year of volatile organic compounds.

(4) R307-150-7 applies to Part 70 sources not included in R307-150-3(2) or R307-150-3(3).

(5) R307-150-9 applies to sources with Standard Industrial Classification codes in the major group 13 that have uncontrolled actual emissions greater than one ton per year for a single pollutant of PM_{10}, $PM_{2.5}$, oxides of nitrogen, oxides of sulfur, carbon monoxide or volatile organic compounds. These sources include, but are not limited to, industries involved in oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; and natural gas processing plants and commercial oil and gas disposal wells, and ponds.[~~ and sites.~~]

(a) Sources that require inventory submittals under R307-150-3(1) through R307-150-3(4) are excluded from the requirements of R307-150-9.

R307-150-4. Sulfur Dioxide Milestone Inventory Requirements.

(1) Annual Sulfur Dioxide Emission Report.

(a) Sources identified in R307-150-3(1) shall submit an annual inventory of sulfur dioxide emissions beginning with calendar year 2003 for all emissions units including fugitive emissions.

(b) The inventory shall include the rate and period of emissions, excess or breakdown emissions, startup and shut down emissions, the specific emissions unit that is the source of the air pollution, type and efficiency of the air pollution control equipment, percent of sulfur content in fuel and how the percent is calculated, and other information necessary to quantify operation and emissions and to evaluate pollution control efficiency. The emissions of a pollutant shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the inventoried time period.

(2) Each source subject to R307-150-4 that is also subject to 40 CFR Part 75 reporting requirements shall submit a summary report of annual sulfur dioxide emissions that were reported to the Environmental Protection Agency under 40 CFR Part 75 in lieu of the reporting requirements in (1) above.

(3) Changes in Emission Measurement Techniques. Each source subject to R307-150-4 that uses a different emission monitoring or calculation method than was used to report their sulfur dioxide emissions in 2006 under R307-150 or 40 CFR Part 75 shall adjust their reported emissions to be comparable to the emission monitoring or calculation method that was used in 2006. The calculations that are

used to make this adjustment shall be included with the annual emission report.

R307-150-5. Sources Identified in R307-150-3(2), Large Major Source Inventory Requirements.

(1) Each large major source shall submit an emission inventory annually beginning with calendar year 2002. The inventory shall include PM[~~10~~]$_{10}$, PM[~~2.5~~]$_{2.5}$, oxides of sulfur, oxides of nitrogen, carbon monoxide, volatile organic compounds, and ammonia for all emissions units including fugitive emissions.

(2) For every third year beginning with 2005, the inventory shall also include all other chargeable pollutants and hazardous air pollutants not exempted in R307-150-8.

(3) For each pollutant specified in (1) or (2) above, the inventory shall include the rate and period of emissions, excess or breakdown emissions, startup and shut down emissions, the specific emissions unit that is the source of the air pollution, composition of air pollutant, type and efficiency of the air pollution control equipment, and other information necessary to quantify operation and emissions and to evaluate pollution control efficiency. The emissions of a pollutant shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the inventoried time period.

R307-150-6. Sources Identified in R307-150-3(3).

(1) Each source identified in R307-150-3(3) shall submit an inventory every third year beginning with calendar year 2002 for all emissions units including fugitive emissions.

(a) The inventory shall include PM[~~10~~]$_{10}$, PM[~~2.5~~]$_{2.5}$, oxides of sulfur, oxides of nitrogen, carbon monoxide, volatile organic compounds, ammonia, other chargeable pollutants, and hazardous air pollutants not exempted in R307-150-8.

(b) For each pollutant, the inventory shall include the rate and period of emissions, excess or breakdown emissions, startup and shut down emissions, the specific emissions unit which is the source of the air pollution, composition of air pollutant, type and efficiency of the air pollution control equipment, and other information necessary to quantify operation and emissions and to evaluate pollution control efficiency. The emissions of a pollutant shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the inventoried time period.

(2) Sources identified in R307-150-3(3) shall submit an inventory for each year after 2002 in which the total amount of PM10, oxides of sulfur, oxides of nitrogen, carbon monoxide, or volatile

organic compounds increases or decreases by 40 tons or more per year from the most recently submitted inventory. For each pollutant, the inventory shall meet the requirements of R307-150-6(1)(a) and (b).

R307-150-7. Sources Identified in R307-150-3(4), Other Part 70 Sources.

(1) Sources identified in R307-150-3(4) shall submit the following emissions inventory every third year beginning with calendar year 2002 for all emission units including fugitive emissions.

(2) Sources identified in R307-150-3(4) shall submit an inventory for each year after 2002 in which the total amount of PM10, oxides of sulfur, oxides of nitrogen, carbon monoxide, or volatile organic compounds increases or decreases by 40 tons or more per year from the most recently submitted inventory.

(3) The emission inventory shall include individual pollutant totals of all chargeable pollutants not exempted in R307-150-8.

R307-150-8. Exempted Hazardous Air Pollutants.

(1) The following air pollutants are exempt from this rule if they are emitted in an amount less than that listed in Table 1.

TABLE 1

POLLUTANT	Pounds/year
Arsenic	0.21
Benzene	33.90
Beryllium	0.04
Ethylene oxide	38.23
Formaldehyde	5.83

(2) Hazardous air pollutants, except for dioxins or furans, are exempt from being reported if they are emitted in an amount less than the smaller of the following:

(a) 500 pounds per year; or

(b) for acute pollutants, the applicable TLV-C expressed in milligrams per cubic meter and multiplied by 15.81 to obtain the pounds-per-year threshold; or

(c) for chronic pollutants, the applicable TLV-TWA expressed in milligrams per cubic meter and multiplied by 21.22 to obtain the pounds-per-year threshold; or

(d) for carcinogenic pollutants, the applicable TLV-C or TLV-TWA expressed in milligrams per cubic meter and multiplied by 7.07 to obtain the pounds-per-year threshold.

R307-150-9 Crude Oil and Natural Gas Source Category

(1) Sources identified in R307-150-3(5) shall submit an inventory every third year beginning with the 2017 calendar year for all emission units.

(a) The inventory shall include the total emissions for PM[~~10~~]$_{10}$, PM[~~2.5~~]$_{2.5}$, oxides of sulfur, oxides of nitrogen, carbon monoxide and volatile organic compounds for each emission unit at the source. The emissions of a pollutant shall be calculated using the emission unit's actual operating hours, product rates, and types of materials processed, stored, or combusted during the inventoried time period. (b) The inventory shall include the type and efficiency of air pollution control equipment.

(c) The inventory shall be submitted in an electronic format determined by the Director specific to this source category.

KEY: air pollution, reports, inventories
Date of Enactment or Last Substantive Amendment: 2017
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Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(c)

R307. Environmental Quality, Air Quality.
R307-401. Permit: New and Modified Sources.
R307-401-1. Purpose.

This rule establishes the application and permitting requirements for new installations and modifications to existing installations throughout the State of Utah. Additional permitting requirements apply to larger installations or installations located in nonattainment or maintenance areas. These additional requirements can be found in R307-403, R307-405, R307-406, R307-420, and R307-421. Modeling requirements in R307-410 may also apply. Each of the permitting rules establishes independent requirements, and the owner or operator must comply with all of the requirements that apply to the installation. Exemptions under R307-401 do not affect applicability of the other permitting rules.

R307-401-2. Definitions.

"Actual emissions" (a) means the actual rate of emissions of an air contaminant from an emissions unit, as determined in accordance with R307-401-2(b) through R307-401-2(d)

(b) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the air contaminant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The director shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(c) The director may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(d) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

"Best available control technology" means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed stationary source or modification which the director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

"Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

"Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

"Emissions unit" means any part of a stationary source that emits or would have the potential to emit any air contaminant.

"Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

"Indirect source" means a building, structure, facility or installation which attracts or may attract mobile source activity that results in emission of a pollutant for which there is a national standard.

"Potential to emit" means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

"Secondary emissions" means emissions which occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

"Stationary source" means any building, structure, facility, or installation which emits or may emit an air contaminant.

R307-401-3. Applicability.

(1) R307-401 applies to any person intending to:

(a) construct a new installation which will or might reasonably be expected to become a source or an indirect source of air pollution, or

(b) make modifications or relocate an existing installation which will or might reasonably be expected to increase the amount or change the effect of, or the character of, air contaminants discharged, so that such installation may be expected to become a source or indirect source of air pollution, or

(c) install a control apparatus or other equipment intended to control emissions of air contaminants.

(2) R307-403, R307-405 and R307-406 may establish additional permitting requirements for new or modified sources.

(a) Exemptions contained in R307-401 do not affect applicability or other requirements under R307-403, R307-405 or R307-406.

(b) Exemptions contained in R307-403, R307-405 or R307-406 do not affect applicability or other requirements under R307-401, unless specifically authorized in this rule.

R307-401-4. General Requirements.

The general requirements in R307-401-4(1) through R307-401-4(3) apply to all new and modified installations, including installations that are exempt from the requirement to obtain an approval order.

(1) Any control apparatus installed on an installation shall be adequately and properly maintained.

(2) If the director determines that an exempted installation is not meeting an approval order or State Implementation Plan limitation, is creating an adverse impact to the environment, or would be injurious to human health or welfare, then the director may require the owner

or operator to submit a notice of intent and obtain an approval order in accordance with R307-401-5 through R307-401-8. The director will complete an appropriate analysis and evaluation in consultation with the owner or operator before determining that an approval order is required.

(3) Low Oxides of Nitrogen Burner Technology.

(a) Except as provided in R307-401-4(3)(b) , whenever existing fuel combustion burners are replaced, the owner or operator shall install low oxides of nitrogen burners or equivalent oxides of nitrogen controls, as determined by the director, unless such equipment is not physically practical or cost effective. The owner or operator shall submit a demonstration that the equipment is not physically practical or cost effective to the director for review and approval prior to beginning construction.

(b) The provisions of (a) above do not apply to non-commercial, residential buildings.

R307-401-5. Notice of Intent.

(1) Except as provided in R307-401-9 through R307-401-17, any person subject to R307-401 shall submit a notice of intent to the director and receive an approval order prior to initiation of construction, modification or relocation. The notice of intent shall be in a format specified by the director.

(2) The notice of intent shall include the following information:

(a) A description of the nature of the processes involved; the nature, procedures for handling and quantities of raw materials; the type and quantity of fuels employed; and the nature and quantity of finished product.

(b) Expected composition and physical characteristics of effluent stream both before and after treatment by any control apparatus, including emission rates, volume, temperature, air contaminant types, and concentration of air contaminants.

(c) Size, type and performance characteristics of any control apparatus.

(d) An analysis of best available control technology for the proposed source or modification. When determining best available control technology for a new or modified source in an ozone nonattainment or maintenance area that will emit volatile organic compounds or nitrogen oxides, the owner or operator of the source shall consider EPA Control Technique Guidance (CTG) documents and Alternative Control Technique documents that are applicable to the source. Best available control technology shall be at least as stringent as any published CTG that is applicable to the source.

(e) Location and elevation of the emission point and other factors relating to dispersion and diffusion of the air contaminant in relation to nearby structures and window openings, and other information necessary to appraise the possible effects of the effluent.

(f) The location of planned sampling points and the tests of the completed installation to be made by the owner or operator when necessary to ascertain compliance.

(g) The typical operating schedule.

(h) A schedule for construction.

(i) Any plans, specifications and related information that are in final form at the time of submission of notice of intent.

(j) Any additional information required by:

(i) R307-403, Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas;

(ii) R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD);

(iii) R307-406, Visibility;

(iv) R307-410, Emissions Impact Analysis;

(v) R307-420, Permits: Ozone Offset Requirements in Davis and Salt Lake Counties; or

(vi) R307-421, Permits: PM10 Offset Requirements in Salt Lake County and Utah County.

(k) Any other information necessary to determine if the proposed source or modification will be in compliance with Title R307.

(3) Notwithstanding the exemption in R307-401-9 through R307-401-16, any person that is subject to R307-403, R307-405, or R307-406 shall submit a notice of intent to the director and receive an approval order prior to initiation of construction, modification, or relocation.

R307-401-6. Review Period.

(1) Completeness Determination. Within 30 days after receipt of a notice of intent, or any additional information necessary to the review, the director will advise the applicant of any deficiency in the notice of intent or the information submitted.

(2) Within 90 days of receipt of a complete application including all the information described in R307- 401-5, the director will

(a) issue an approval order for the proposed construction, installation, modification, relocation, or establishment pursuant to the requirements of R307-401-8, or

(b) issue an order prohibiting the proposed construction, installation, modification, relocation or establishment if it is deemed that any part of the proposal is inadequate to meet the applicable requirements of R307.

(3) The review period under R307-401-6(2) [~~above~~] may be extended by up to three 30-day extensions if more time is needed to review the proposal.

R307-401-7. Public Notice.

(1) Issuing the Notice. Prior to issuing an approval or disapproval order, the director will advertise intent to approve or disapprove in a newspaper of general circulation in the locality of the proposed construction, installation, modification, relocation or establishment.

(2) Opportunity for Review and Comment.

(a) At least one location will be provided where the information submitted by the owner or operator, the director's analysis of the notice of intent proposal, and the proposed approval order conditions will be available for public inspection.

(b) Public Comment.

(i) A 30-day public comment period will be established.

(ii) A request to extend the length of the comment period, up to 30 days, may be submitted to the director within 15 days of the date the notice in R307-401-7(1) is published.

(iii) Public Hearing. A request for a hearing on the proposed approval or disapproval order may be submitted to the director within 15 days of the date the notice in R307-401-7(1) is published.

(iv) The hearing will be held in the area of the proposed construction, installation, modification, relocation or establishment.

(v) The public comment and hearing procedure shall not be required when an order is issued for the purpose of extending the time required by the director to review plans and specifications.

(3) The director will consider all comments received during the public comment period and at the public hearing and, if appropriate, will make changes to the proposal in response to comments before issuing an approval order or disapproval order.

R307-401-8. Approval Order.

(1) The director will issue an approval order if the following conditions have been met:

(a) The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. When determining best available control technology for a new or modified source in an ozone nonattainment or maintenance area that will emit volatile organic compounds or nitrogen oxides, best available control technology shall be at least as stringent as any Control Technique Guidance document that has been published by EPA that is applicable to the source.

(b) The proposed installation will meet the applicable requirements of:

(i) R307-403, Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas;

(ii) R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD);

(iii) R307-406, Visibility;

(iv) R307-410, Emissions Impact Analysis;

(v) R307-420, Permits: Ozone Offset Requirements in Davis and Salt Lake Counties;

(vi) R307-210, National Standards of Performance for New Stationary Sources;

(vii) National Primary and Secondary Ambient Air Quality Standards;

(viii) R307-214, National Emission Standards for Hazardous Air Pollutants;

(ix) R307-110, Utah State Implementation Plan; and

(x) all other provisions of R307.

(2) The approval order will require that all pollution control equipment be adequately and properly maintained.

(3) Receipt of an approval order does not relieve any owner or operator of the responsibility to comply with the provisions of R307 or the State Implementation Plan.

(4) To accommodate staged construction of a large source, the director may issue an order authorizing construction of an initial stage prior to receipt of detailed plans for the entire proposal provided that, through a review of general plans, engineering reports and other information the proposal is determined feasible by the director under the intent of R307. Subsequent detailed plans will then be processed as prescribed in this paragraph. For staged construction projects the previous determination under R307-401-8(1) and (2) will be reviewed and modified as appropriate at the earliest reasonable time prior to commencement of construction of each independent phase of the proposed source or modification.

(5) If the director determines that a proposed stationary source, modification or relocation does not meet the conditions established in (1) above, the director will not issue an approval order.

R307-401-9. Small Source Exemption.

(1) A small stationary source is exempt from the requirement to obtain an approval order in R307-401-5 through R307-401-8 if the following conditions are met.

(a) its actual emissions are less than 5 tons per year per air contaminant of any of the following air contaminants: sulfur dioxide, carbon monoxide, nitrogen oxides, PM_{10}, ozone, or volatile organic compounds;

(b) its actual emissions are less than 500 pounds per year of any hazardous air pollutant and less than 2000 pounds per year of any combination of hazardous air pollutants;

(c) its actual emissions are less than 500 pounds per year of any air contaminant not listed in (a)(or (b) above and less than 2000 pounds per year of any combination of air contaminants not listed in (a) or (b) above.

(d) Air contaminants that are drawn from the environment through equipment in intake air and then are released back to the environment without chemical change, as well as carbon dioxide, nitrogen, oxygen, argon, neon, helium, krypton, xenon should not be included in emission calculations when determining applicability under (a) through (c) above.

(2) The owner or operator of a source that is exempted from the requirement to obtain an approval order under (1) above shall no longer be exempt if actual emissions in any subsequent year exceed the emission thresholds in (1) above. The owner or operator shall submit a notice of intent under R307-401-5 no later than 180 days after the end of the calendar year in which the source exceeded the emission threshold.

(3) Small Source Exemption - Registration. The director will maintain a registry of sources that are claiming an exemption under R307-401-9. The owner or operator of a stationary source that is claiming an exemption under R307-401-9 may submit a written registration notice to the director. The notice shall include the following minimum information:

(a) identifying information, including company name and address, location of source, telephone number, and name of plant site manager or point of contact;

(b) a description of the nature of the processes involved, equipment, anticipated quantities of materials used, the type and quantity of fuel employed and nature and quantity of the finished product;

(c) identification of expected emissions;

(d) estimated annual emission rates;

(e) any control apparatus used; and

(f) typical operating schedule.

(4) An exemption under R307-401-9 does not affect the requirements of R307-401-17, Temporary Relocation.

(5) A stationary source that is not required to obtain a permit under R307-405 for greenhouse gases, as defined in R307-405-3(9)(a), is not required to obtain an approval order for greenhouse gases under R307-401. This exemption does not affect the requirement to obtain

an approval order for any other air contaminant emitted by the stationary source.

R307-401-10. Source Category Exemptions.

The source categories described in R307-401-10 are exempt[~~ed~~] from the requirement to obtain an approval order found in R307-401-5 through R307-401-8. The general provisions in R307-401-4 shall apply to these sources.

(1) Fuel-burning equipment in which combustion takes place at no greater pressure than one inch of mercury above ambient pressure with a rated capacity of less than five million BTU per hour using no other fuel than natural gas or LPG or other mixed gas that meets the standards of gas distributed by a utility in accordance with the rules of the Public Service Commission of the State of Utah, unless there are emissions other than combustion products.

(2) Comfort heating equipment such as boilers, water heaters, air heaters and steam generators with a rated capacity of less than one million BTU per hour if fueled only by fuel oil numbers 1 - 6,

(3) Emergency heating equipment, using coal or wood for fuel, with a rated capacity less than 50,000 BTU per hour.

(4) Exhaust systems for controlling steam and heat that do not contain combustion products.

(5) A well site as defined in 40 CFR 60.5430a[~~ and~~], including centralized tank batteries, that is not a major source as defined in R307-101-2, and is registered with the Division as required by R307-505.

R307-401-11. Replacement-in-Kind Equipment.

(1) Applicability. Existing process equipment or pollution control equipment that is covered by an existing approval order or State Implementation Plan requirement may be replaced using the procedures in (2) below if:

(a) the potential to emit of the process equipment is the same or lower;

(b) the number of emission points or emitting units is the same or lower;

(c) no additional types of air contaminants are emitted as a result of the replacement;

(d) the process equipment or pollution control equipment is identical to or functionally equivalent to the replaced equipment;

(e) the replacement does not change the basic design parameters of the process unit or pollution control equipment;

(f) the replaced process equipment or pollution control equipment is permanently removed from the stationary source, otherwise permanently disabled, or permanently barred from operation;

(g) the replacement process equipment or pollution control equipment does not trigger New Source Performance Standards or National Emissions Standards for Hazardous Air Pollutants under 42 U.S.C. 7411 or 7412; and

(h) the replacement of the control apparatus or process equipment does not violate any other provision of Title R307.

(2) Replacement-in-Kind Procedures.

(a) In lieu of filing a notice of intent under R307-401-5, the owner or operator of a stationary source shall submit a written notification to the director before replacing the equipment. The notification shall contain a description of the replacement-in-kind equipment, including the control capability of any control apparatus and a demonstration that the conditions of (1) above are met.

(b) If the replacement-in-kind meets the conditions of (1) above, the director will update the source's approval order and notify the owner or operator. Public review under R307-401-7 is not required for the update to the approval order.

(3) If the replaced process equipment or pollution control equipment is brought back into operation, it shall constitute a new emissions unit.

R307-401-12. Reduction in Air Contaminants.

(1) Applicability. The owner or operator of a stationary source of air contaminants that reduces or eliminates air contaminants is exempt from the requirement to submit a notice of intent and obtain an approval order prior to construction if:

(a) the project does not increase the potential to emit of any air contaminant or cause emissions of any new air contaminant, and

(b) the director is notified of the change and the reduction of air contaminants is made enforceable through an approval order in accordance with (2) below.

(2) Notification. The owner or operator shall submit a written description of the project to the director no later than 60 days after the changes are made. The director will update the source's approval order or issue a new approval order to include the project and to make the emission reductions enforceable. Public review under R307-401-7 is not required for the update to the approval order.

R307-401-13. Plantwide Applicability Limits.

A plantwide applicability limit under R307-405-21 does not exempt a stationary source from the requirements of R307-401.

R307-401-14. Used Oil Fuel Burned for Energy Recovery.

(1) Definitions.

"Boiler" means boiler as defined in R315-1-1(b).

"Used Oil" is defined as any oil that has been refined from crude oil, used, and, as a result of such use contaminated by physical or chemical impurities.

(2) Boilers burning used oil for energy recovery are exempt from the requirement to obtain an approval order in R307-401-5 through R307-401-8 if the following requirements are met:

(a) the heat input design is less than one million BTU/hr;

(b) contamination levels of all used oil to be burned do not exceed any of the following values:

(i) arsenic - 5 ppm by weight,

(ii) cadmium - 2 ppm by weight,

(iii) chromium - 10 ppm by weight,

(iv) lead - 100 ppm by weight,

(v) total halogens - 1,000 ppm by weight,

(vi) Sulfur - 0.50% by weight; and

(c) the flash point of all used oil to be burned is at least 100 degrees Fahrenheit.

(3) Testing. The owner or operator shall test each load of used oil received or generated as directed by the director to ensure it meets these requirements. Testing may be performed by the owner/operator or documented by test reports from the used fuel oil vendor. The flash point shall be measured using the appropriate ASTM method as required by the director. Records for used oil consumption and test reports are to be kept for all periods when fuel-burning equipment is in operation. The records shall be kept on site and made available to the director or the director's representative upon request. Records must be kept for a three-year period.

R307-401-15. Air Strippers and Soil Venting Projects.

(1) The owner or operator of an air stripper or soil venting system that is used to remediate contaminated groundwater or soil is exempt from the notice of intent and approval order requirements of R307-401-5 through R307-401-8 if the following conditions are met:

(a) the estimated total air emissions of volatile organic compounds from a given project are less than the de minimis emissions listed in R307-401-9(1)(a), and

(b) the level of any one hazardous air pollutant or any combination of hazardous air pollutants is below the levels listed in R307-410-5(1)(c)(i)(C).

(2) The owner or operator shall submit documentation that the project meets the exemption requirements in R307-401-15(1) to the director prior to beginning the remediation project.

(3) After beginning the soil remediation project, the owner or operator shall submit emissions information to the director to verify that the emission rates of the volatile organic compounds and hazardous

air pollutants in R307-401-15(1) are not exceeded.

(a) Emissions estimates of volatile organic compounds shall be based on test data obtained in accordance with the test method in the EPA document SW-846, Test #8260c or 8261a, or the most recent EPA revision of either test method if approved by the director.

(b) Emissions estimates of hazardous air pollutants shall be based on test data obtained in accordance with the test method in EPA document SW-846, Test #8021B or the most recent EPA revision of the test method if approved by the director.

(c) Results of the test and calculated annual quantity of emissions of volatile organic compounds and hazardous air pollutants shall be submitted to the director within one month of sampling.

(d) The test samples shall be drawn on intervals of no less than twenty-eight days and no more than thirty-one days (i.e., monthly) for the first quarter, quarterly for the first year, and semi-annually thereafter or as determined necessary by the director.

(4) The following control devices do not require a notice of intent or approval order when used in relation to an air stripper or soil venting project exempted under R307-401-15:

(a) thermodestruction unit with a rated input capacity of less than five million BTU per hour using no other auxiliary fuel than natural gas or LPG, or

(b) carbon adsorption unit.

R307-401-16. De minimis Emissions From Soil Aeration Projects.

An owner or operator of a soil remediation project is not subject to the notice of intent and approval order requirements of R307-401-5 through R307-401-8 when soil aeration or land farming is used to conduct a soil remediation, if the owner or operator submits the following information to the director prior to beginning the remediation project:

(1) documentation that the estimated total air emissions of volatile organic compounds, using an appropriate sampling method, from the project are less than the de minimis emissions listed in R307-401-9(1)(a);

(2) documentation that the levels of any one hazardous air pollutant or any combination of hazardous air pollutants are less than the levels in R307-410-5(1)(d); and

(3) the location of the remediation and where the remediated material originated.

R307-401-17. Temporary Relocation.

The owner or operator of a stationary source previously approved under R307-401 may temporarily relocate and operate the stationary source at any site for up to 180 working days in any calendar year not to exceed 365 consecutive days, starting from the initial relocation date. The director will evaluate the expected emissions impact at the site and compliance with applicable Title R307 rules as the bases for determining if approval for temporary relocation may be granted. Records of the working days at each site, consecutive days at each site, and actual production rate shall be submitted to the director at the end of each 180 calendar days. These records shall also be kept on site by the owner or operator for the entire project, and be made available for review to the director as requested. R307-401-7, Public Notice, does not apply to temporary relocations under R307-401-17.

R307-401-18. Eighteen Month Review.

Approval orders issued by the director in accordance with the provisions of R307-401 will be reviewed eighteen months after the date of issuance to determine the status of construction, installation, modification, relocation or establishment. If a continuous program of construction, installation, modification, relocation or establishment is not proceeding, the director may revoke the approval order.

R307-401-19. General Approval Order.

(1) The director may issue a general approval order that would establish conditions for similar new or modified sources of the same type or for specific types of equipment. The general approval order may apply throughout the state or in a specific area.

(a) A major source or major modification as defined in R307-403, R307-405, or R307-420 for each respective area is not eligible for coverage under a general approval order.

(b) A source that is subject to the requirements of R307-403-5 is not eligible for coverage under a general approval order.

(c) A source that is subject to the requirements of R307-410-4 is not eligible for coverage under a general approval order unless a demonstration that meets the requirements of R307-410-4 was conducted.

(d) A source that is subject to the requirements of R307-410-5(1)(c)(ii) is not eligible for coverage under a general approval order unless a demonstration that meets the requirements of R307-410-5(1)(c)(ii) was conducted.

(e) A source that is subject to the requirements of R307-410-5(1)(c)(iii) is not eligible for coverage under a general approval order.

(2) A general approval order shall meet all applicable requirements of R307-401-8.

(3) The public notice requirements in R307-401-7 shall apply to a general approval order except that the director will advertise the notice of intent in a newspaper of statewide circulation.

(4) Application.

(a) After a general approval order has been issued, the owner or operator of a proposed new or modified source may apply to be covered under the conditions of the general approval order.

(b) The owner or operator shall submit the application on forms provided by the director in lieu of the notice of intent requirements in R307-401-5 for all equipment covered by the general approval order.

(c) The owner or operator may request that an existing, individual approval order for the source be revoked, and that it be covered by the general approval order.

(d) The owner or operator that has applied to be covered by a general approval order shall not initiate construction, modification, or relocation until the application has been approved by the director.

(5) Approval.

(a) The director will review the application and approve or deny the request based on criteria specified in the general approval order for that type of source. If approved, the director will issue an authorization to the applicant to operate under the general approval order.

(b) The public notice requirements in R307-401-7 do not apply to the approval of an application to be covered under the general approval order.

(c) The director will maintain a record of all stationary sources that are covered by a specific general approval order and this record will be available for public review.

(6) Exclusions and Revocation.

(a) The director may require any source that has applied for or is authorized by a general approval order to submit a notice of intent and obtain an individual approval order under R307-401-8. Cases where an individual approval order will be required include, but are not limited to, the following:

(i) the director determines that the source does not meet the criteria specified in the general approval order;

(ii) the director determines that the application for the general approval order did not contain all necessary information to evaluate applicability under the general approval order;

(iii) modifications were made to the source that were not authorized by the general approval order or an individual approval order;

(iv) the director determines the source may cause a violation of a national ambient air quality standard; or

(v) the director determines that one is required based on the compliance history and current compliance status of the source or applicant.

(b)(i) Any source authorized by a general approval order may request to be excluded from the coverage of the general approval order by submitting a notice of intent under R307-401-5 and receiving an individual approval order under R307-401-8.

(ii) When the director issues an individual approval order to a source subject to a general approval order, the applicability of the general approval order to the individual source is revoked on the effective date of the individual approval order.

(7) Modification of General Approval Order. The director may modify, replace, or discontinue the general approval order.

(a) Administrative corrections may be made to the existing version of the general approval order. These corrections are to correct typographical errors or similar minor administrative changes.

(b) All other modifications or the discontinuation of a general approval order shall not apply to any source authorized under previous versions of the general approval order unless the owner or operator submits an application to be covered under the new version of the general approval order. Modifications under R307-401-19(7)(b) shall meet the public notice requirements in R307-401-19(3).

(c) A general approval order shall be reviewed at least every three year. The review of the general approval order shall follow the public notice requirements of R307-401-19(3).

(8) Modifications at a source covered by a general approval order. A source may make modifications only as authorized by the approved general approval order. Modifications outside the scope authorized by the approved general approval order shall require a new application for either an individual approval order under R307-401-8 or a general approval order under R307-401-19.

KEY: air pollution, permits, approval orders, greenhouse gases
Date of Enactment or Last Substantive Amendment: 2017
Notice of Continuation: June 6, 2012
Authorizing, and Implemented or Interpreted Law: 19-2-104(3)(q); 19-2-108

R307. Environmental Quality, Air Quality.

R307-504. Oil and Gas Industry: Tank Truck Loading.

R307-504-1. Purpose.

R307-504 establishes control requirements for the loading of liquids containing volatile organic compounds (VOCs) at oil or gas well sites.

R307-504-2. Definitions.

The definitions in 40 CFR 60, Subpart OOOO Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, [~~that are~~] incorporated by reference in R307-210, apply to R307-504.

"Bottom Filling" means the filling of a tank through an inlet at or near the bottom of the tank designed to have the opening covered by the liquid after the pipe normally used to withdraw liquid can no longer withdraw any liquid.

"Submerged Fill Pipe" means any fill pipe with a discharge opening which is entirely submerged when the liquid level is six inches above the bottom of the tank and the pipe normally used to withdraw liquid from the tank can no longer withdraw any liquid.

"Vapor Capture Line" means a connection hose, fitted with a valve that can be connected to tanker trucks during truck loading operations. The vapor capture line shall be designed, installed, operated, and maintained to optimize capture efficiency.[~~ used to collect VOC emissions from truck loading operations. The other end of the vapor capture line is connected to an existing tank battery or enclosed vapor combustor for the destruction of VOC emissions.~~]

"Well [~~production facility~~]Site" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells.

R307-504-3. Applicability.

(1) R307-504-4(1) applies to any person who loads or permits the loading of any intermediate hydrocarbon liquid or produced water at [~~source at~~] a well [~~production facility~~]site after January 1, 2015.

(2) R307-504-4(2) applies to owners and operators that are required to control emissions from storage vessels in accordance with R307-506.

R307-504-4. Tank Truck Loading Requirements.

(1) Tanker trucks used for intermediate hydrocarbon liquid or produced water shall be loaded using bottom filling or a submerged fill pipe.

(2) VOC emissions during truck loading operations shall be controlled at all times using a vapor capture line. The vapor capture

line shall [~~achieve no less than 70% capture efficiency and 98% destruction efficiency (95% efficiency from VOC control device and 3%~~] ~~from auto ignitor requirements of R307-503) resulting in an overall control efficiency of no less than 68.6%. An equivalent control technology can be utilized if approved by the director and capable of meeting or exceeding a 68.6% overall control efficiency.~~]be connected from the tanker truck to a control device or process, resulting in a minimum 95 percent VOC destruction efficiency.

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.

R307-505. Oil and Gas Industry: Registration Requirements.

R307-505-1. Purpose.

R307-505 establishes requirements for sources in the oil and gas industry to register with the Division.

R307-505-2. Applicability.

(1) R307-505 applies to new and existing operations at a source with Standard Industrial Classification codes in the major group 13, which includes but is not limited to industries involved in oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; natural gas processing plants and commercial oil and gas disposal wells, and evaporation ponds.

(a) A source that is subject to an approval order in accordance with R307-401-8 is exempt from R307-505.

R307-505-3. Registration Requirements

(1) An owner or operator of a source identified in R307-505-2 that begins operations on or after January 1, 2018, shall register with the director 30 days prior to commencing operation.

(2) An owner or operator of a source identified in R307-505-2 that is in operation before January 1, 2018, shall register with the director by July 1, 2018.

(3) An owner or operator shall update the registration information within 30 days of any of the following:

(a) changes to company name,

(b) removal or addition of control devices, or

(c) termination of operations.

(4) Registration shall be completed online in a format provided by the Division and shall include the following general information: company name, mailing address, source location, source manager or point of contact, process description, capacity and quantity of emitting equipment on-site, fuel type of combustion related equipment (i.e. diesel, natural gas, propane, or field gas), emissions control devices installed, emissions and certification that the facility is in compliance with R307-506 through R307-510.

KEY: air pollution, oil, gas

Date of Enactment or Last Substantive Amendment: 2017

Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307-506. Oil and Gas Industry: Storage Vessel.

R307-506-1. Purpose.

R307-506 establishes requirements to control emissions of volatile organic compounds (VOCs) from storage vessels associated with [~~oil and gas operations~~] a well site.

R307-506-2. Definitions.

"Centralized Tank Battery" means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site.

"Emergency Relief Storage Vessel" means a storage vessel receiving oil, condensate, or produced water as a result of emergency situations, process upsets, or other equipment malfunctions.

"Modification to a well site" means;

(1) a new well is drilled at an existing well site,

(2) a well at an existing well site is hydraulically fractured, or

(3) a well at an existing well site is hydraulically refractured.

"Storage Vessel" means storage vessel as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210.

"Uncontrolled emissions" means actual emissions or the potential to emit without consideration of controls.

R307-506-3. Applicability.

(1) R307-506 applies to each storage vessel located at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-506 shall apply to centralized tank batteries.

([~~a~~]3) R307-506 does not apply to storage vessels that are subject to an approval order issued under R307-401-8.

R307-506-4. Storage Vessel Requirements.

(1) Thief hatches on storage vessels shall be kept closed and latched except during vessel unloading or other maintenance activities.

(2) All storage vessels located at a well site [~~A storage vessel or collection of storage vessels,~~]that [~~is~~]are in operation as of January 1, 2018, with a site-wide throughput of 8,000 barrels or greater of crude oil or 2,000 barrels or greater of condensate per year on a rolling 12-month basis shall comply with R304-506-4(2)(a) unless the exemption in R307-506-

4(2)(b) applies.

(a) VOC emissions from storage vessels shall either be routed to a process unit where the emissions are recycled, incorporated into a product and/or recovered, or be routed to a VOC control device that is in compliance with R307-508.

(b) All storage vessels located at a well site [~~or collection of storage vessels~~] shall be exempt from R307-506-4(2)(a) if combined VOC emissions are demonstrated to be less than four tons per year of uncontrolled emissions on a rolling [~~twelve~~]12-month basis.[~~ by the following methods:~~]

(i) VOC working and breathing losses, and flash emissions shall be calculated using direct site-specific sampling data and any software program or calculation methodology in use by industry that is based on AP-42 Chapter 7.

[(~~ii)VOC flash emissions shall be calculated using site-specific sampling data and the Vasquez-Beggs Equation.~~

~~(iii) VOC emissions determined by an alternative method approved by the Director.~~]

(3) All [~~S~~]storage vessels that begin operations on or after January 1, 2018, are required to control VOC emissions in accordance with R307-506-4(2)(a) upon startup of operation for a minimum of one year.

(4)An emergency storage vessel located at a well site shall be exempt from R307-506-4(2)(a), if it meets the following requirements:

(i) The emergency storage vessel shall not be used as an active storage tank.

(ii) The owner or operator shall empty the emergency storage vessel no later than 15 days after receiving fluids.

(iii) The emergency storage vessel shall be equipped with a liquid level gauge or equivalent device.

([~~4~~]5) An owner or operator that is required to control emissions in accordance with R307-506-4(2) and R307-506-4(3) shall inspect at least once a month each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.

([~~5~~]6) Modification to a well site shall require a re-evaluation of site-wide throughput and/or emissions in accordance with R307-506-4(2).

([~~6~~]7) After a minimum of one year of operation, controls may be removed if [~~when~~] site-wide throughput is less than 8,000 barrels of crude oil or 2,000 barrels of condensate on a rolling [~~twelve-~~]12-month basis or uncontrolled actual emissions are demonstrated to be less than four tons per year.[~~ after one year of operation.~~]

R307-506-5. Recordkeeping

(1) Records of each [~~thief hatch~~] closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device[~~ inspection~~] shall be kept for three years.

(a) Records of each [~~thief hatch~~] closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass device[~~ inspection~~] shall include the date of the inspection, the status of [~~the ~~]each [~~thief hatch~~] closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass device, and the date of corrective action taken if required.

(2) Records of crude oil throughput shall be kept for three years and shall be determined on a monthly basis using the production data reported to the Utah Division of Oil, Gas, and Mining.

(3) Records of emission calculations, actual emissions, and site-specific sampling data used to determine compliance with R307-506-4(2)(b) shall be kept for a period of three years, post registration.[~~as long as the well site is in operation.~~]

(4) Records of emergency storage vessel usage shall be kept for a period of three years.

(a) Records of emergency storage vessel usage shall include the date the vessel received fluids or was discovered to have received fluids, the date the overflow tank was emptied, and the volume of fluids emptied in barrels.

KEY: air pollution, oil, gas

Date of Enactment or Last Substantive Amendment: [~~October 7, 2014~~]2017

Authorizing, and Implemented or Interpreted Law: 19-2-104(1(a)

R307. Environmental Quality, Air Quality.

R307-507. Oil and Gas Industry: Dehydrators.

R307-507-1. Purpose.

R307-507 establishes requirements to control emissions of volatile organic compounds (VOCs) from dehydrators associated with [~~oil and gas operations~~] a well site.

R307-507-2. Definitions.

"Dehydrator" means dehydrator as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, which is incorporated by reference in R307-210.

"Uncontrolled emissions" means actual or potential emissions without consideration of controls.

R307-507-3. Applicability.

(1) R307-507 applies to each dehydrator located at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-507 shall apply to centralized tank batteries, as defined in R307-506-2.

([~~a~~]3) R307-507 does not apply to a dehydrator that is subject to an approval order issued under R307-401-8.

R307-507-4. Dehydrator Requirements.

(1) Dehydrators with VOC emissions of four tons of uncontrolled emissions per year or greater, either individually or combined with VOC emissions from storage vessels, shall either be routed to a process unit where the emissions are recycled, incorporated into a product, and/or recovered, or be routed to a VOC control device that is in compliance with R307-508. Dehydrators in operation before January 1, 2018, shall determine applicability with calculated actual emissions. Dehydrators in operation on or after January 1, 2018, shall determine applicability using potential to emit.

(2) An owner or operator that is required to control emissions in accordance with R307-507-4(1) shall inspect, at least once a month, each closed vent system, including vessel openings, thief hatches, and bypass devices, for defects that can result in air emissions according to 40 CFR 60.5416a(c).

(a) If defects are discovered, the defects shall be corrected or repaired within 15 days of identification.

(3) Modification to a well site shall require a re-evaluation of emissions in accordance with R307-507-4(1).

([~~2~~]4) After a minimum of one year of operation, [~~C~~]controls may be removed [~~when~~]if uncontrolled actual emissions, individually or combined with VOC emissions from storage vessels, are less than four tons per year on a rolling [~~twelve~~]12-month basis.

R307-507-5. Recordkeeping

(1) Records of emission calculations shall be kept for all periods the plant is in operation if a control device is not installed on-site.

(2) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass devices, shall be kept for three years.

(a) Records of each closed vent system inspection, including vessel openings, thief hatches, pressure relief devices and bypass devices, shall include the date of the inspection, the status of each closed vent system, including vessel openings, thief hatches, pressure relief devices and bypass devices, and the date of corrective action taken, if required.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.

R307-508. Oil and Gas Industry: VOC Control Devices.

R307-508-1. Purpose.

R307-508 establishes requirements for VOC control devices associated with [~~oil and gas operations~~]well sites used to control emissions of VOCs.

R307-508-2. Applicability.

(1) R307-508 applies to each VOC control device located at a well site as defined in 40 CFR 60.5430a Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(2) R307-508 shall apply to centralized tank batteries, as defined in R307-506-2.

([~~a~~]3) R307-508 does not apply to VOC control devices that are subject to an approval order issued under R307-401-8.

R307-508-3. VOC Control Device Requirements.

(1) A VOC control device required by R307-506 or R307-507 must have a control efficiency of 95% or greater.

(a) The VOC control device shall operate with no visible emissions.

(b) The VOC control device must comply with R307-503.

(2) [~~To show compliance with the control efficiency, the VOC control device shall be operated according to the manufacturer's specifications and be certified by the manufacturer to reduce VOC emissions by 95% or greater.~~] A well site shall demonstrate compliance by meeting the performance test methods and procedures specified in 40 CFR 60.5413.

(3) VOC control devices and all associated equipment shall be inspected monthly by audio, visual, or olfactory (AVO) means to ensure the integrity of the equipment is maintained and is operational. If equipment is not operational, corrective action shall be taken within 15 days of discovery.

R307-508-4. Recordkeeping.

(1) The owner[~~/~~]or operator shall keep and maintain records of [~~the following:~~
~~(a)~~] the VOC control device's control efficiency guaranteed by the manufacturer. These records shall be retained for the life of the control equipment on site.

([~~b~~]2) The owner or operator shall keep and maintain records of the manufacturer's written operating and maintenance instructions. These records shall be retained for the life of the control equipment.

([~~c~~]3)The owner or operator shall keep and maintain records of the VOC control device AVO inspections. These shall be retained for a minimum of three years. These records shall include:

([~~i~~]a) the date of the inspection;

([~~ii~~]b) the status of the control device and associated equipment; and

([~~iii~~]c) date of corrective action taken, if applicable.

KEY: air pollution, oil, gas

Date of Enactment or Last Substantive Amendment: 2017

Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.

R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements.

R307-509-1. Purpose.

R307-509 establishes requirements for conducting leak detection and repairs at [~~oil and gas operations~~] well sites to control emissions of volatile organic compounds.

R307-509-2. Definitions

"Difficult-to-Monitor" means difficult-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

"Fugitive emissions" are considered any visible emissions observed using optical gas imaging or a Method 21 instrument reading of 500 ppm or greater.

"Fugitive emissions component" means any component that has the potential to emit fugitive emissions of VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems, thief hatches or other openings, compressors, instruments, and meters.

"Unsafe-to-Monitor" means unsafe-to-monitor as defined 40 CFR 60.5397a, which is incorporated by reference in R307-210.

R307-509-3. Applicability.

(1) R307-509 applies to each fugitive emissions component at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution and is required to control emissions in accordance with R307-506 and R307-507.

(a) A source meeting the requirements of 40 CFR 60.5397a is meeting the requirements of this rule.

(b) Sources subject to R307-509, are subject until the well is shut in.

([~~a~~]c) R307-509 does not apply to a fugitive emissions component that is subject to an approval order issued under R307-401-8.

R307-509-4. Leak Detection and Repair Requirements.

(1) Applicable sources shall comply with the following:

(a) The owner[~~/~~]or operator shall develop an emissions monitoring plan that [~~will~~]shall be available upon request to review for each individual well site. At a minimum, the plan shall include:

(i) monitoring frequency;

(ii) monitoring technique and equipment;

(iii) procedures and timeframes for identifying and repairing leaks;

(iv) recordkeeping practices; and

(v) calibration and maintenance procedures for monitoring equipment.

(b) The plan shall address monitoring for difficult-to-monitor and unsafe-to-monitor components.

(c) The owner[~~/~~]or operator shall conduct monitoring surveys on site to observe each fugitive emissions component for fugitive emissions.

(d) Monitoring surveys shall be conducted according to the following schedule:

(i) No later than [~~180~~]365 days after January 1, 2018, or no later than 60 days after startup of production, as defined in 40 CFR 60 Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, whichever is later.

(ii) Semiannually after the initial monitoring survey. Consecutive semiannual monitoring surveys shall be conducted at least four months apart.

(iii) Annually after the initial monitoring survey for "difficult-to-monitor" components.

(iv) As required by the owner[~~/~~]or operator's monitoring plan for "unsafe-to-monitor" components.

(e) Monitoring surveys shall be conducted using one or both of the following to detect fugitive emissions:

(i) Optical gas imaging (OGI) equipment. OGI equipment shall be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions source.

(ii) Monitoring equipment that meets U.S. EPA Method 21, 40 CFR Part 60, Appendix A.

(f) If fugitive emissions are detected at any time, the owner[~~/~~]or operator shall repair the fugitive emissions component as soon as possible but no later than 15 calendar days after detection. If the repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement shall be completed during the next well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 24 months, whichever is earlier.

(g) The owner[~~/~~]or operator shall resurvey the repaired or replaced fugitive emission component no later than 30 calendar days after the fugitive emission component was repaired.

R307-509-5. Recordkeeping.

(1) The owner[~~/~~]or operator shall maintain records of the emissions monitoring plan[~~,~~].These records shall be retained for the life of the well site.

(2) The owner or operator shall maintain records of the monitoring surveys, repairs, and resurveys. These records shall be retained for a minimum of three years.

KEY: air pollution, oil, gas
Date of Enactment or Last Substantive Amendment: 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

R307. Environmental Quality, Air Quality.
R307-510. Oil and Gas Industry: Natural Gas Engine Requirements.
R307-510-1. Purpose.

R307-510 establishes control requirements for stationary engines associated with [~~oil and gas operations~~] well sites.[~~to control emissions nitrogen oxide emissions.~~]

R307-510-2. Definitions.

"Site hp" means the total horse power rating of all engines within the boundaries of the source.

R307-510-[~~2~~]3. Applicability.

(1) R307-510 applies to each natural gas-fired engine at a well site as defined in 40 CFR 60.5430a, Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, that began operations, installed new engines, or made modifications to existing engines after January 1, 2016.

(2) R307-506 shall apply to centralized tank batteries, as defined in R307-506-2.

([~~a~~]3) R307-510 does not apply to a natural gas-fired engine that is subject to an approval order issued under R307-401-8.

R307-510-~~3~~4. Engine Requirements.

(1) Regardless of construction, reconstruction, or modification date, each stationary engine at a well site shall comply with the emission standards listed in Table 1 when the engine is installed, relocated, or modified.[~~40 CFR Subpart JJJJ when the engine is installed or modified.~~]

Table 1

Maximum Engine hp	Emission Standards in (g/hp-hr)			
	NO_x	CO	VOC	$HC+NO_x$
≥25 hp and < 100 hp	-	4.85	-	2.83
≥100 hp	1.0	2.0	0.7	-

(2) The owner or operator shall either:

(a) purchase a certified stationary internal combustion engine as defined in 40 CFR 60.4248, or

(b) conduct an initial performance test according to 40 CFR 60.4244.

([~~2~~]3) Each engine shall vent exhaust gases vertically unrestricted with the following stack height requirements:

([i]a) For [~~S~~]site hp ratings of 306 or greater,[~~higher shall vent exhaust vertically unrestricted with~~] each engine shall have an attached stack height of no less than 10 feet.

([~~ii~~]b) For [~~S~~]site hp ratings of 151 to 305 hp,[~~horsepower shall vent exhaust vertically unrestricted with~~] each engine shall have an attached stack height of no less than 8 feet.

([~~iii~~]c)For [~~S~~]site hp ratings of 150 hp [~~horsepower~~] or less, there are [~~have~~] no stack height requirements on engines.

R307-510-4. Recordkeeping.

For each engine on site, the owner or operator shall maintain records of the engine certification or initial performance test for the period of time the engine is on the well site. [~~The owner/operator shall maintain documentation demonstrating that each stationary engine on-site meets the requirements contained in R307-510-3.~~]

KEY: air pollution, oil, gas

Date of Enactment or Last Substantive Amendment: 2017

Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

Amend R307-150. Emission Inventories.

I. Whether a fiscal impact to business is expected as a result of the proposed rule and a description of why

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule. This rule requires each company to submit an emissions inventory every three years that includes "the total emissions for PM10, PM2.5, oxides of sulfur, oxides of nitrogen, carbon monoxide and volatile organic compounds for each emission unit at the source." R307-150-9(a). The cost will depend on the amount of time and the amount of money the company chooses to pay its staff to prepare the inventory.

II. An estimate of the total number of business establishments in Utah expected to be impacted

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule. Collectively, these companies own approximately 3,500 wells that are located on State land.

III. An estimate of the small business establishments in Utah expected to be impacted

Of the 30 companies that will be impacted, at least 10 are small businesses.

IV. A description of the sources of cost or savings as well as the expected net savings or cost to business establishments and small business establishments as a result of the proposed rule over a one-year period, identifying one-time and ongoing costs

The source of the cost to companies as a result of this rule is the requirement to submit an emissions inventory every three years that includes "the total emissions for PM10, PM2.5, oxides of sulfur, oxides of nitrogen, carbon monoxide and volatile organic compounds for each emission unit at the source." R307-150-9(a). The inventory must also include "the type and efficiency of air pollution control equipment." This inventory is submitted in an electronic format, and staff at the Division are working to create a web application that will allow companies to submit their inventories online.

Many of the companies impacted by this rule already have the data necessary for the inventory, which will make the fiscal impact of this rule minimal. Companies that do not have the data readily available should be able to calculate the data fairly easily. The cost will depend on the amount of time and the amount of money the company chooses to pay its staff to prepare the inventory. The cost to businesses over a one-year period will also vary depending on the amount of regulated equipment that is owned by the company. Initially, there may be a one-time cost to businesses to set up a database where they can track information related to the inventory. This should consist of an excel spreadsheet and may cost a few hundred dollars of staff time to organize. This one time cost would be less for small businesses because there are fewer sites to account for. After the database is set up, the costs will be the result of staff time used to input new information every three years to create an inventory and submit it to the Division of Air

Quality. Assuming this takes about two hours per well site, and a company pays someone 75 dollars an hour to complete the inventory, the cost of the rule will be approximately 150 dollars per well site. This cost will be the same for small and large businesses. Since the inventory is only required every three years, the ongoing cost will be approximately 50 dollars per well site annually.

V.

The above analysis represents DAQ's best estimate as to the fiscal impact this rule amendment will have on businesses. Division of Air Quality Staff anticipate that most companies will already have access to a majority of the data that is required for the inventory. This ensures that any costs discussed in the analysis are minimal. The Division welcomes comments during the public comment period that provide further information regarding costs or savings that may result from the amendments being proposed.

Amend R307-401. Permit: New and Modified Sources.

9.a.

After conducting a thorough analysis, it was determined that this proposed rule will not result in a fiscal impact to businesses. This is because the rule provides an exemption from obtaining an approval order for well sites that are registered with the Division of Air Quality. The exemption does not provide any additional cost to businesses in Utah.

Amend R307-504. Oil and Gas Industry: Tank Truck Loading.

9.a.

After conducting a thorough analysis, it was determined that this proposed rule will not result in a fiscal impact to businesses in Utah. This rule requires well sites that are subject to new rule R307-506 to implement volatile organic compound (VOC) emission controls for the loading of liquids containing VOCs at well sites. The rule generally applies to well sites that need to have a permit. A permit would require the same VOC emission controls that are contained in these proposed amendments. Therefore, there is no additional cost for businesses as a result of these amendments.

Amend R307-505. Oil and Gas Industry: Registration Requirements.

I. Whether a fiscal impact to business is expected as a result of the proposed rule and a description of why

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule. This rule requires each company to register its new and existing operations with standard industrial classification codes in the major group 13. This includes industries involved in oil and natural gas exploration, production, and transmission operations; well production facilities; natural gas compressor stations; natural gas processing plants and commercial oil and gas disposal wells, and evaporation ponds. This rule will result in a fiscal impact on businesses because it requires them to register with the director.

II. An estimate of the total number of business establishments in Utah expected to be impacted

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule.

III. An estimate of the small business establishments in Utah expected to be impacted

Of the 30 companies that will be impacted, at least 10 are small businesses.

IV. A description of the sources of cost or savings as well as the expected net savings or cost to business establishments and small business establishments as a result of the proposed rule over a one-year period, identifying one-time and ongoing costs

The source of the cost to companies as a result of this rule is the requirement to register its operations with the Division. Registration includes the following general information; company name, mailing address, source location, source manager or point of contact, process description, capacity and quantity of emitting equipment on-site, fuel type of combustion related equipment (i.e. diesel, natural gas, propane, or field gas), emissions control devices installed, emissions, and certification that the facility is in compliance with R307-506 through R307-510. This data should not be difficult to retrieve, and there will be minimal costs associated with the registration requirement.

The cost will be the amount the company pays an employee to register online using the Division's web based tool and any potential fees associated with registration that the Utah Legislature might approve in the future. This should cost no more than 100 dollars per registration. This is a one-time cost for existing sources, which must be completed before July 1, 2018. An ongoing cost of less than 100 dollars will also be associated with the need to update a registration when changes are made to the company name, the emission control device strategies are altered, or operations are terminated. There will also be an ongoing cost of less than 100 dollars per registration for future registrations. These costs will be the same for small and large businesses. Larger companies will ultimately pay more because they will be required to submit more registrations to account for their larger inventory.

There is also a potential savings for both large and small businesses. Since sites that are registered with the Division are exempt from the requirement to obtain an approval order, the businesses will not have to spend thousands of dollars for each permit.

V.

The above analysis represents DAQ's best estimate as to the fiscal impact this rule amendment will have on businesses. Division of Air Quality Staff anticipate that most companies will already have access to a majority of the data that is required for the registration. This ensures that any costs discussed in the analysis are minimal. The Division welcomes comments during the public comment period that provide further information regarding costs or savings that may result from the amendments being proposed.

Amend R307-506. Oil and Gas Industry: Registration Requirements.

I. Whether a fiscal impact to business is expected as a result of the proposed rule and a description of why

Yes, a fiscal impact is expected as a result of proposed rule R307-506.

II. An estimate of the total number of business establishments in Utah expected to be impacted

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule.

III. An estimate of the small business establishments in Utah expected to be impacted

Of the 30 companies that will be impacted, at least 10 are small businesses.

IV. A description of the sources of cost or savings as well as the expected net savings or cost to business establishments and small business establishments as a result of the proposed rule over a one-year period, identifying one-time and ongoing costs

Most well sites will not be impacted by this rule because they are already required to obtain a permit that would include the storage vessel requirements that are found in R307-506. However, new sources that begin operations on or after January 1, 2018, may be impacted. Sources that begin operations on or after January 1, 2018, and have actual emissions that are less than four tons per year, will need to operate with controls for one year in order to demonstrate whether their actual emissions qualify for an exemption from the control requirements under R307-506-4(6). The requirement to operate for a year with controls is not a requirement in the current rules. Currently, sources can show that they are a small source that is exempt from the requirement to obtain a permit by using their potential to emit. This is a one-time cost that would only apply to sources that operate for a year and then show that they have less than four tons of annual emissions. This cost will be approximately 40,000 to 60,000 dollars to install the control equipment. The cost will be the same for small and large businesses. The cost is considered a one-time cost because the control equipment is removed after a year if the exemption applies, and the equipment can be used on other sites. There may be an ongoing cost if new well sites are constructed and the equipment that is already owned by the company is unusable on those sites. This ongoing cost would be an additional 40,000 to 60,0000 dollars per site.

V.

The above analysis represents DAQ's best estimate as to the fiscal impact this rule amendment will have on businesses. Division of Air Quality Staff anticipate that most companies will rarely encounter a situation where this rule will result in a fiscal impact that would not already have occurred under the current air quality rules. This is because companies will typically not dig a well if the well would not be productive enough to require controls under R307-506 or require a permit under the current air quality rules. The Division welcomes comments during the public comment period that provide further information regarding costs or savings that may result from the amendments being proposed.

Amend R307-507. Oil and Gas Industry: Dehydrators.

9.a.

After conducting a thorough analysis, it was determined that this proposed rule will not result in a fiscal impact to businesses in Utah. This rule requires emission controls for Volatile organic compounds (VOCs) that are emitted from dehydrators associated with oil and gas operations. This rule will not result in a cost to businesses because it is only regulating new sources that would currently be required to get a permit. A minor source permit for dehydrators associated with oil and gas operations would include requirements that are equivalent to the requirements in these rules. Therefore, R307-507 does not add any additional costs to businesses.

Amend R307-508. Oil and Gas Industry: VOC Control Devices.

I. Whether a fiscal impact to business is expected as a result of the proposed rule and a description of why

Yes, a minor fiscal impact is expected as a result of proposed rule R307-508.

II. An estimate of the total number of business establishments in Utah expected to be impacted

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule.

III. An estimate of the small business establishments in Utah expected to be impacted

Of the 30 companies that will be impacted, at least 10 are small businesses.

IV. A description of the sources of cost or savings as well as the expected net savings or cost to business establishments and small business establishments as a result of the proposed rule over a one-year period, identifying one-time and ongoing costs

Most well sites will not be impacted by this rule because they are already required to obtain a permit that would include the control device efficiency and minimum equipment inspection requirements that are found in R307-508-3. Also, sources that are already subject to an approval order are exempt from these requirements, and they will not have any additional costs as a result of this proposed rule.

However, there are some new sources that begin operations on or after January 1, 2018 that may be impacted because they have to have VOC control devices as required by R307-506. The sources that begin operations on or after January 1, 2018, and have actual emissions that are less than four tons per year, will need to operate with controls for one year in order to demonstrate whether their actual emissions qualify for an exemption under R307-506-4(6). The requirement to operate for a year with controls is not currently a part of the air quality rules. Currently, sources can show that they are a small source that is exempt from the requirement to obtain a permit by using their potential to emit. The few sources that will need to operate for a year to demonstrate that they qualify for the exemption will have to use controls that meet the efficiency and equipment inspection requirements that are found in R307-508-3.

This is a one-time cost that would only apply to sources that operate for a year and then show that they have less than four tons of annual emissions. The cost will be equal to the cost of installing the control equipment required by R307-306. Control equipment that meets the requirements of this rule amendment is approximately 40,000-60,000 dollars. The cost will be the same for both small and large businesses. The cost is considered a one-time cost because the control equipment is removed after a year, and it can be used on other sites. There may be an ongoing cost if new well sites are being drilled and the equipment that is already owned by the company is unusable. This cost is the same cost that is caused by R307-506. It is a one-time cost that is only incurred once for both R307-506 and R307-508.

V.

The above analysis represents DAQ's best estimate as to the fiscal impact this rule amendment will have on businesses. Division of Air Quality Staff anticipate that most companies will rarely encounter a situation where this rule will result in a fiscal impact that would not already have occurred under the current air quality rules. This is because companies will typically not dig a well if the well would not be productive enough to require controls under R307-506 or require a permit under the current air quality rules. The Division welcomes comments during the public comment period that provide further information regarding costs or savings that may result from the amendments being proposed.

Amend R307-509. Oil and Gas Industry: Leak Detection and Repair Requirements.

I. Whether a fiscal impact to business is expected as a result of the proposed rule and a description of why

Yes, a fiscal impact is expected as a result of proposed rule R307-509.

II. An estimate of the total number of business establishments in Utah expected to be impacted

The Division of Air Quality (the Division) has identified 30 companies that may be impacted by this rule.

III. An estimate of the small business establishments in Utah expected to be impacted

Of the 30 companies that will be impacted, at least 10 are small businesses.

IV. A description of the sources of cost or savings as well as the expected net savings or cost to business establishments and small business establishments as a result of the proposed rule over a one-year period, identifying one-time and ongoing costs

Many well sites will not be impacted by this rule because they are already subject to leak detection and repair (LDAR) inspection requirements through their permit. Existing small sources will also be exempt from the LDAR requirement as long as they can demonstrate that they are exempt in accordance with R307-506 and R307-507. Well sites that do not meet the minor-source exemption threshold and have failed to obtain the required permit do not face additional fiscal impacts as a result of this rule. This is because those sites should have obtained a permit, and the permit would require LDAR inspections.

The only well sites that this rule would have a fiscal impact on are those sites that have to be in operation for a year to demonstrate the small source exemption for the purpose of R307-506. Storage vessels that begin operations on or after January 1, 2018, are required to control VOC emissions in accordance with R307-506-4(2)(a) to demonstrate that they would be exempt from maintaining emission controls on their equipment. These sources would need to conduct up to two LDAR inspections during the year that they are maintaining emission controls on their equipment as required by R307-506-4(2)(a).

The EPA has estimated that hiring a consultant to conduct an LDAR inspection would cost approximately $600 dollars per site. *See* 80 Fed. Reg. at 56,641 (TSD at 72 "The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well production site."). Since each site will be inspected twice, the total cost would be 1,200 dollars per site. The state of Colorado estimated a lower cost of 450 dollars per site for similar LDAR inspections. A large business that is already conducting many LDAR inspections for their permitted sources may find the price to be less than a smaller company that may have only a few well sites. In order to aid businesses, the Division of Air Quality will provide a camera to owners that would like to be trained on how to use it for LDAR inspections. This service will significantly reduce the cost of conducting LDAR inspections. Therefore, the cost of the LDAR inspections required by this rule will be about 600 dollars per site, but it could be less if a business takes advantage of the Division's services. This will be a one-year cost because controls can be removed if the small source exemption applies, and R307-309 would no longer require LDAR for that site. If the small source exemption does not apply, then the site would need to follow the permit-by-rule, which does not require any costs in addition to what the current permitting system would currently require. This is because LDAR inspections are already required for newly permitted sources.

If a leak is detected, there could also be a one-time cost for repairs. The cost for repairing a leak can range between zero and 1000's of dollars depending on the type of leak and the cost of preventing further leakage. This cost for repair will be the same for both small and large businesses.

V.

The above analysis represents DAQ's best estimate as to the fiscal impact this rule amendment will have on businesses. Division of Air Quality Staff anticipate that most companies will rarely encounter a situation where this rule will result in a fiscal impact that would not already have occurred under the current air quality rules. This is because companies will typically not dig a well if the well would not be productive enough to require controls under R307-506 or require a permit under the current air quality rules. The Division welcomes comments during the public comment period that provide further information regarding costs or savings that may result from the amendments being proposed.

Amend R307-510. Oil and Gas Industry: Leak Detection and Repair Requirements.

9.a.

After conducting a thorough analysis, it was determined that this proposed rule will not result in a fiscal impact to businesses in Utah. This rule requires certain stack heights for venting emissions from engines. Since the rule only applies to sites that began operations, installed new engines, or made modifications to existing engines after January 1, 2016, there is no fiscal impact on businesses. This is because these sites would currently be required to meet similar stack height requirements regardless as to whether this proposed rule was adopted. These requirements would be part of the source's permit.

Appendix 1: Regulatory Impact Summary Table*

Fiscal Costs	FY 2018	FY 2019	FY 2020
State Government	$0	$0	$0
Local Government	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Person	$0	$0	$0
Total Fiscal Costs:	**$0**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Government	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits:	**$0**	**$0**	**$0**
Net Fiscal Benefits:	$0	$0	$0

***This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts for State Government, Local Government, Small Businesses and Other Persons are described above. Inestimable impacts for Non-Small Businesses are described below.**

Appendix 2: Regulatory Impact to Non-Small Businesses

There are five oil and gas extraction companies (NAICS 2111) operating in Utah that will incur a one-time cost to comply with the amendments to R307-504 (based on 2014 Tank Control inventory). These businesses will experience a fiscal cost associated with the installation of vapor capture lines at each site. The full impact to these non-small businesses cannot be estimated as necessary because the cost of installation can vary from site to site, depending on cost variances of supplies, design, and installation methods. It is estimated that the cost of each site, depending on operator preference, will be between $1,000 and $10,000.

ITEM 5

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-085-17

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Rules Coordinator

DATE: December 19, 2017

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-101-3. Version of Code of Federal Regulations Incorporated by Reference.

R307-101-3, Version of Code of Federal Regulations Incorporated by Reference, must be updated periodically to reflect changes to the federal air quality regulations as published in Title 40 of the Code of Federal Regulations (40 CFR). All published changes to 40 CFR that are relevant to the Utah Air Quality Rules from July 1, 2016, to July 1, 2017, are listed in the attached document. The rule has been amended to identify the most recent version of 40 CFR, July 1, 2017, as the version that is incorporated throughout the Utah Air Quality Rules.

Recommendation: Staff recommends that the Board propose the amended R307-101-3 for public comment.

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R307. Environmental Quality, Air Quality.

R307-101. General Requirements.

R307-101-3. Version of Code of Federal Regulations Incorporated by Reference.

Except as specifically identified in an individual rule, the version of the Code of Federal Regulations (CFR) incorporated throughout R307 is dated July 1, 201[~~6~~]7.

KEY: air pollution, definitions

Date of Enactment or Last Substantive Amendment: [~~June 8, 2017~~]2018

Notice of Continuation: May 8, 2014

Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

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Summary of Code of Federal Regulations Changes from July 1, 2016, to July 1, 2017

Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
R307-101-2	40 CFR 51.100(s)	40 CFR 51.100(s)(1) was revised by amending the introductory text. This final action finds Ethane (JFE-347pcf2) negligibly reactive with respect to its contribution to tropospheric O_3 formation and thus exempts ethane from EPA's definition of VOC. **81 Fed. Reg. 50330 (August 1, 2016)**
	40 CFR 93, Subpart B	40 CFR 93, Subpart B §93.153(b)(1) revised $PM_{2.5}$ information , distinguishing limits between Moderate NAA's (100 Tons/year) and Serious NAA's (70 Tons/year). 40 CFR 93, Subpart B §93.153(b)(2) revised $PM_{2.5}$ types (direct emissions, SO_2, NO_x, VOC, and Ammonia) under one rate of 100 Tons/year. Additionally, the line, "All maintenance areas" was added with a rate of 100 Tons/year. **81 Fed. Reg. 58162 (August 24, 2016)**
R307-170-7	40 CFR 75, Appendix A, Section 6.2	No Change
R307-221-2	Definitions 40 CFR 60.751	No Change
R307-221-3	40 CFR 60.752 through 60.759, including Appendix A	Appendix A–1 Method 1-2F §11.2.1.2 was revised by amending the text to correct the spelling of "<u>d</u>istances." Removed "Figure 1-2" in §17.0 Method 2 §6.7 was revised by amending the text to include the following sentence: "<u>Calibration of the Type S pitot tube requires a standard pitot tube for reference</u>." §10.1.2.3 was revised by amending the following text to "This velocity must be constant with time to guarantee <u>constant and</u> steady flow during <u>the entire period of</u> calibration. <u>A centrifugal fan is recommended for this purpose, as no flow rate adjustment for back pressure of the fan is allowed during the calibration process</u>." §10.1.3.4 was revised by amending the text to include the following sentence: "<u>Make no adjustment to the fan speed or other wind tunnel volumetric flow control device between this reading and the corresponding Type S pitot reading</u>." §10.1.3.7 was revised by amending the following text to "Repeat Steps 10.1.3.3 through 10.1.3.6 until three pairs of Δp readings have been obtained for the A side of the Type S pitot tube<u>, with all the paired observations conducted at a constant fan speed (no changes to fan velocity between observed readings)</u>."

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		§10.1.4.1.3 was revised by amending the following text to "Therefore, to minimize the blockage effect, the calibration point may be a few inches off-center if necessary, but no closer to the outer wall of the wind tunnel than 4 inches. The [~~actual~~] maximum allowable blockage [~~effect will be negligible when the theoretical blockage~~], as determined by a projected-area model of the probe sheath, is 2 percent or less of the duct cross-sectional area [~~for assemblies without external sheaths~~] (Figure 2–10a)[~~, and 3 percent or less for assemblies with external sheaths (Figure 2-10b)~~]. If the pitot and/or probe assembly blocks more than 2 percent of the cross-sectional area at an insertion point only 4 inches inside the wind tunnel, the diameter of the wind tunnel must be increased." §10.1.4.3 was revised by amending the following text to "(see section [~~10.1.4.4~~] 12.4.4)" Figure 2-10: diagram is updated. Appendix A–2 Method 2G-3C §6.11.1 was revised by amending the text "The projected area of the portion of the probe head, shaft, and attached devices inside the wind tunnel during calibration shall represent no more than ~~4~~ 2 percent of the cross-sectional area of the tunnel. [~~The projected area shall include the combined area of the calibration pitot tube and the tested probe if both probes are placed simultaneously in the same cross-sectional plane in the wind tunnel, or the larger projected area of the two probes if they are placed alternately in the wind tunnel~~] If the pitot and/or probe assembly blocks more than 2 percent of the cross-sectional area at an insertion point only 4 inches inside the wind tunnel, the diameter of the wind tunnel must be increased." §6.11.2 was revised by amending the text "The wind tunnel should be capable of achieving and maintaining a constant and steady [~~velocities~~] velocity between 6.1 m/sec and 30.5 m/ sec (20 ft/sec and 100 ft/sec) for the entire calibration period for each selected calibration velocity." §10.6.6 was revised by amending the text to include the following sentence: "Record the rotational speed of the fan or indicator of wind tunnel velocity control (damper setting, variac rheostat, etc.) and make no adjustment to fan speed or wind tunnel velocity control between this observation and the Type S probe reading." §10.6.8 was revised by amending the text to include the following sentence: "Adjustments made to the fan speed or other changes to the system designed to change the air flow velocity of the wind tunnel between observation of the calibration pitot tube (ΔP_{xtd}) and the Type S pitot tube invalidates the reading and the observation must be repeated." §6.3 was revised by amending the following text to "Analyzer Linearity Check and Calibration. Perform this test before sample analysis. [~~Using the gas mixtures in section 5.1, verify the detector linearity over the range of suspected~~

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Summary of Code of Federal Regulations Changes from July 1, 2016, to July 1, 2017

Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		~~sample concentrations with at least three points per compound of interest. This initial check may also serve as the initial instrument calibration. All subsequent calibrations may be performed using a single-point standard gas provided the calibration point is within 20 percent of the sample component concentration. For each instrument calibration, record the carrier and detector flow rates, detector filament and block temperatures, attenuation factor, injection time, chart speed, sample loop volume, and component concentrations. Plot a linear regression of the standard concentrations versus area values to obtain the response factor of each compound. Alternatively, response factors of uncorrected component concentrations (wet basis) may be generated using instrumental integration. NOTE: Peak height may be used instead of peak area throughout this method]~~." Created §6.3.1 "Using the gas mixtures in section 5.1, verify the detector linearity over the range of suspected sample concentrations with at least three concentrations per compound of interest. This initial check may also serve as the initial instrument calibration." Created §6.3.2 "You may extend the use of the analyzer calibration by performing a singlepoint calibration verification. Calibration verifications shall be performed by triplicate injections of a single-point standard gas. The concentration of the single-point calibration must either be at the midpoint of the calibration curve or at approximately the source emission concentration measured during operation of the analyzer." Created §6.3.3 "Triplicate injections must agree within 5 percent of their mean, and the average calibration verification point must agree within 10 percent of the initial calibration response factor. If these calibration verification criteria are not met, the initial calibration described in section 6.3.1, using at least three concentrations, must be repeated before analysis of samples can continue." Created §6.3.4 "For each instrument calibration, record the carrier and detector flow rates, detector filament and block temperatures, attenuation factor, injection time, chart speed, sample loop volume, and component concentrations." Created §6.3.5 "Plot a linear regression of the standard concentrations versus area values to obtain the response factor of each compound. Alternatively, response factors of uncorrected component concentrations (wet basis) may be generated using instrumental integration. Note: Peak height may be used instead of peak area throughout this method." Appendix A–3 Method 4 Created §10.3 "Field Balance Calibration Check. Check the calibration of the balance used to weigh impingers with a weight that is at least 500g or within 50g of a loaded impinger. The weight must be ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference-see 40 CFR 60.17)

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		Class 6 (or better). Daily, before use, the field balance must measure the weight within ± 0.5g of the certified mass. If the daily balance calibration check fails, perform corrective measures and repeat the check before using balance." Created §12.2.5 "Using F-factors to determine approximate moisture for estimating moisture content where no wet scrubber is being used, for the purpose of determining isokinetic sampling rate settings with no fuel sample, is acceptable using the average Fc or Fd factor from Method 19 (see Method 19, section 12.3.1). If this option is selected, calculate the approximate moisture as follows: B_{ws} = BH + BA+ BF Where: B_A = Mole Fraction of moisture in the ambient air. B_{ws} = Mole fraction of moisture in the stack gas. F_d = Volume of dry combustion components per unit of heat content at 0 percent oxygen, dscf/106. Btu (scm/J). See Table 19–2 in Method 19. F_w = Volume of wet combustion components per unit of heat content at 0 percent oxygen, wet. scf/106 Btu (scm/J). See Table 19–2 in Method 19. %RH = Percent relative humidity (calibrated hygrometer acceptable), percent. P_{Bar} = Barometric pressure, in. Hg. T = Ambient temperature, °F. W = Percent free water by weight, percent. O_2 = Percent oxygen in stack gas, dry basis, percent." Additionally, examples of functions are listed. §16.4 was revised by amending the text to include the following "Using F-factors to determine moisture is an acceptable alternative to Method 4 for a combustion stack not using a scrubber, and where a fuel sample is taken during the test run and analyzed for development of an Fd factor (see Method 19, section 12.3.2), and where stack O2 content is measured by Method 3A or 3B during each test run." and "Note: Free water in fuel is minimal for distillate oil and gases, such as propane and natural gas, so this step may be omitted for those fuels." Method 5 §6.1.1.9 was revised by amending the following text to "Metering System. Vacuum gauge, leak-free pump, calibrated temperature sensors [~~(rechecked at at least one point after each test)~~], dry gas meter (DGM) capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5–1. [~~Alternatively, an Isostack metering system may be used if all Method 5 calibrations are performed, with the exception of those related to ΔH@ in Section 9.2.1, wherein the sample flow rate system shall be calibrated in lieu of ΔH@ and shall not deviate by more than 5 percent.~~] Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of

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		determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall allow periodic checks of isokinetic rates." §8.7.6.2.5 was revised by amending the following text to "[~~After ensuring that all joints have been wiped clean of silicone grease,~~] Clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone." Created §10.7 "Field Balance Calibration Check. Check the calibration of the balance used to weigh impingers with a weight that is at least 500g or within 50g of a loaded impinger. The weight must be ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 6 (or better). Daily before use, the field balance must measure the weight within ±0.5g of the certified mass. If the daily balance calibration check fails, perform corrective measures and repeat the check before using balance." Created §10.8 "Analytical Balance Calibration. Perform a multipoint calibration (at least five points spanning the operational range) of the analytical balance before the first use, and semiannually thereafter. The calibration of the analytical balance must be conducted using ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 2 (or better) tolerance weights. Audit the balance each day it is used for gravimetric measurements by weighing at least one ASTM E617–13 Class 2 tolerance (or better) calibration weight that corresponds to 50 to 150 percent of the weight of one filter or between 1g and 5g. If the scale cannot reproduce the value of the calibration weight to within 0.5 mg of the certified mass, perform corrective measures, and conduct the multipoint calibration before use." Method 5H Created §10.4 "Field Balance Calibration Check. Check the calibration of the balance used to weigh impingers with a weight that is at least 500g or within 50g of a loaded impinger. The weight must be ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 6 (or better). Daily before use, the field balance must measure the weight within ± 0.5g of the certified mass. If the daily balance calibration check fails, perform corrective measures and repeat the check before using balance." Created §10.5 "Analytical Balance Calibration. Perform a multipoint calibration (at least five points spanning the operational range) of the analytical balance before the first use, and semiannually thereafter. The calibration of the analytical balance must be conducted using ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 2 (or better) tolerance weights. Audit the balance each day it is used for gravimetric measurements by weighing at least one ASTM E617–13 Class 2 tolerance (or better) calibration weight that corresponds to 50 to 150 percent of the weight of one filter or between 1g

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		and 5g. If the scale cannot reproduce the value of the calibration weight to within 0.5 mg of the certified mass, perform corrective measures, and conduct the multipoint calibration before use." Method 5I Created §10.1 "Field Balance Calibration Check. Check the calibration of the balance used to weigh impingers with a weight that is at least 500g or within 50g of a loaded impinger. The weight must be ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 6 (or better). Daily, before use, the field balance must measure the weight within ±0.5g of the certified mass. If the daily balance calibration check fails, perform corrective measures and repeat the check before using balance." Created §10.2 "Analytical Balance Calibration. Perform a multipoint calibration (at least five points spanning the operational range) of the analytical balance before the first use, and semiannually thereafter. The calibration of the analytical balance must be conducted using ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 2 (or better) tolerance weights. Audit the balance each day it is used for gravimetric measurements by weighing at least one ASTM E617–13 Class 2 tolerance (or better) calibration weight that corresponds to 50 to 150 percent of the weight of one filter or between 1g and 5g. If the scale cannot reproduce the value of the calibration weight to within 0.5 mg of the certified mass, perform corrective measures and conduct the multipoint calibration before use." Appendix A–4 Method 6C §8.3 was revised by amending the following text to "Interference Check. You must follow the procedures of Section 8.2.7 of Method 7E to conduct an interference check, substituting SO2 for NOX as the method pollutant. For dilution-type measurement systems, you must use the alternative interference check procedure in Section 16 and a co-located, unmodified Method 6 sampling train. [~~Quenching in fluorescence analyzers must be evaluated and remedied unless a dilution system and ambient-level analyzer is used. This may be done by preparing the calibration gas to contain within 1 percent of the absolute oxygen and carbon dioxide content of the measured gas, preparing the calibration gas in air and using vendor nomographs, or by other acceptable means.~~] Method 7E §8.1.2 was revised by amending the following text, striking the numbering "If the concentration at each traverse point differs from the mean concentration for all traverse points by no more than: [~~(a)~~] ±5.0 percent of the mean concentration; or [~~(b)~~] ±0.5 ppm (whichever is less restrictive), the gas stream is considered unstratified and you may collect samples from a single point that most closely matches the mean. If the 5.0 percent or 0.5 ppm criterion is not

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		met, but the concentration at each traverse point differs from the mean concentration for all traverse points by no more than:[~~(a)~~] ±10.0 percent of the mean; or ~~(b)~~ ±1.0 ppm (whichever is less restrictive), the gas stream is considered to be minimally stratified, and you may take samples from three points." Additionally, text was revised to update measurements in the following sentence "Alternatively, if a twelve-point stratification test was performed and the emissions were shown to be minimally stratified (all points within ±10.0 percent of their mean or within ±1.0 ppm), and if the stack diameter (or equivalent diameter, for a rectangular stack or duct) is greater than 2.4 meters (7.8 ft), then you may use 3-point sampling and locate the three points along the measurement line exhibiting the highest average concentration during the stratification test, at 0.4, [~~1.0~~] 1.2 and 2.0 meters from the stack or duct wall." §8.2.7 was revised by amending the following text to "Conduct an interference response test of the gas analyzer prior to its initial use in the field. If you have multiple analyzers of the same make and model, you need only perform this alternative interference check on one analyzer. You may also meet the interference check requirement if the instrument manufacturer performs this or a similar check on an analyzer of the same make and model of analyzer that you use and provides you with documented results. [~~Analytical quenching must be evaluated and remedied unless a dilution system and ambient-level analyzer are used. The analyzer must be checked for quenching at concentrations of approximately 4 and 12 percent CO2 at a mid-range concentration for each analyzer range which is commonly used. The analyzer must be rechecked after it has been repaired or modified or on another periodic basis.~~]" §12.8 changes equation shown in Eq. 7E-8 Method 10 §6.2.5 was revised by amending the following text to "Leak-test the bag in the laboratory before using by evacuating with a pump followed by a dry gas meter. When the evacuation is complete, there should be no flow through the meter. [~~Gas tanks may be used in place of bags if the samples are analyzed within one week.~~] Created §6.2.6 "Sample Tank. Stainless steel or aluminum tank equipped with a pressure indicator with a minimum volume of 4 liters." §8.4.2 was revised by amending the following text to "Integrated Sampling. Evacuate the flexible bag or sample tank. Set up the equipment as shown in Figure 10–1 with the bag disconnected." Method 10A §6.1.6 Although listed, I cannot find any difference between the existing and revised versions of this section.

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		§6.1.7 was revised by replacing the text to "Sample Tank. Stainless steel or aluminum tank equipped with a pressure indicator with a minimum volume of 10 liters." §6.1.8 was previously §6.1.7. There were no text revisions. §6.1.9 was previously §6.1.8 There were no text revisions. §6.1.10 was previously §6.1.9 There were no text revisions. §6.1.11 was previously §6.1.10 There were no text revisions. §8.1 was revised by amending the following text to "Sample Bag or Tank Leak-Checks. While a [~~bag~~] leak-check is required after bag or sample tank use, it should also be done before the bag or sample tank is used for sample collection. The tank should be leak-checked according to the procedure specified in section 8.1.2 of Method 25. The bag should be leak-checked in the inflated and deflated condition according to the following procedure:" §8.2.1 was revised by amending the following text to "Evacuate and leak check the sample bag [~~completely using a vacuum pump~~] or tank as specified in section 8.1. Assemble the apparatus as shown in Figure 10A–1. Loosely pack glass wool in the tip of the probe." §8.2.1 was revised by amending the following text to "Connect the evacuated bag or sample tank to the system, record the starting time, and sample at a rate of 300 ml/ min for 30 minutes, or until the bag is nearly full, or the sample tank reaches ambient pressure." Method 10B §6.1 was revised by amending the following text to "Sample Collection. Same as in Method 10A, section 6.1 (paragraphs 6.1.1 through 6.1.11)." Method 15 §8.3.2 was revised by amending the following text to "Only H2S (or other permeant) need be used to recalibrate the GC/FPD analysis system and the dilution system. Partial recalibration may be performed at the midlevel calibration gas concentration or at a concentration measured in the samples but not less than the lowest calibration standard used in the initial calibration. Compare the calibration curves obtained after the runs to the calibration curves obtained under section 10.3."

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		Appendix A-6 Method 16C §12.1 adds the Nomenclature "CS = Calibration span, ppmv." §12.2 changes equation shown in Eq. 16C-1 Method 18 Removed §8.2.1.5.2.3 "[~~Analyze the two field audit samples as described in Section 9.2 by connecting each bag containing an audit gas mixture to the sampling valve. Calculate the results; record and report the data to the audit supervisor.~~]" Appendix A-7 Method 25C §9.1 updates table by revising the following text "~~8.4.1~~ 8.4.2 | Verify that landfill gas sample contains less than 20 percent N_2 or 5 percent O_2 . | Ensures that ambient air was not drawn into the landfill gas sample and gas was sampled from an appropriate location." §12.1 adds the Nomenclatures "CmN2 = Measured N2 concentration, fraction in landfill gas. CmOx = Measured Oxygen concentration, fraction in landfill gas. COx = Oxygen concentration in the diluted sample gas." §12.3 was revised by amending the following text to "[~~NMOC Concentration. Use the following equation to calculate the concentration of NMOC for each sample tank.~~] Nitrogen Concentration in the landfill gas. Use equation 25C–2 to calculate the measured concentration of nitrogen in the original landfill gas." Additionally, §12.3 Changes the equation shown in Eq. 25C-2. Created §12.4 "Oxygen Concentration in the landfill gas. Use equation 25C–3 to calculate the measured concentration of oxygen in the original landfill gas." §12.4 also adds the equation shown in Eq. 25C-3. Created §12.5 "You must correct the NMOC Concentration for the concentration of nitrogen or oxygen based on which gas or gases passes the requirements in section 9.1."

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		Created §12.5.1 "NMOC Concentration with nitrogen correction. Use Equation 25C–4 to calculate the concentration of NMOC for each sample tank when the nitrogen concentration is less than 20 percent.." §12.5.1 also adds the equation shown in Eq. 25C-4. Created §12.5.2 "NMOC Concentration with oxygen correction. Use Equation 25C–5 to calculate the concentration of NMOC for each sample tank if the landfill gas oxygen is less than 5 percent and the landfill gas nitrogen concentration is greater than 20 percent." §12.5.2 also adds the equation shown in Eq. 25C-5. Appendix A-8 Method 26 §13.3 was revised by amending the following text to "Detection Limit. A typical IC instrumental detection limit for Cl^- is 0.2 μg/ml. Detection limits for the other analyses should be similar. Assuming 50 ml liquid recovered from both the acidified impingers, and the basic impingers, and [~~0.06~~] 0.12 dscm (4.24 dscf) of stack gas sampled, then the analytical detection limit in the stack gas would be about [~~0.1~~] 0.05 ppm for HCl and Cl2, respectively." Method 26A §4.3 was revised by adding the following text to "High concentrations of nitrogen oxides (NO_x) may produce sufficient nitrate (NO_3^-) to interfere with measurements of very low Br^- levels. Dissociating chloride salts (e.g., ammonium chloride) at elevated temperatures interfere with halogen acid measurement in this method. Maintaining particulate probe/filter temperatures between 120°C and 134°C (248°F and 273°F) minimizes this interference." §8.1.6 was revised by adding the following text to "NOTE: It is critical that this procedure is repeated until the cyclone is completely dry." Method 29 §8.2.9.3 was revised by adding the following text to "[~~If no visible deposits remain after the water rinse, no further rinse is necessary. However, if deposits remain on the impinger surfaces, w~~]Wash ~~them~~ the two permanganate impingers with 25 ml of 8 N HCl, and place the wash in a separate sample container labeled No. 5C containing 200 ml of water. First, place 200 ml of water in the container. Then wash the impinger walls and stem with the 8 N HCl by turning the impinger on its side and rotating it so that the HCl contacts all inside surfaces. Use a total of only 25 ml of 8 N HCl for rinsing *both permanganate impingers combined*. Rinse the first impinger, then pour the actual rinse used for the first impinger into the second impinger for its rinse. Finally, pour the 25 ml of 8 N HCl rinse carefully into the container with the 200 ml of water. Mark the height of the fluid level on the outside of the container to determine if leakage occurs during transport"

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
		Created §10.4 "Field Balance Calibration Check. Check the calibration of the balance used to weigh impingers with a weight that is at least 500g or within 50g of a loaded impinger. The weight must be ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference-see 40 CFR 60.17) Class 6 (or better). Daily before use, the field balance must measure the weight within ±0.5g of the certified mass. If the daily balance calibration check fails, perform corrective measures and repeat the check before using balance." Created §10.5 "Analytical Balance Calibration. Perform a multipoint calibration (at least five points spanning the operational range) of the analytical balance before the first use, and semiannually thereafter. The calibration of the analytical balance must be conducted using ASTM E617–13 ''Standard Specification for Laboratory Weights and Precision Mass Standards'' (incorporated by reference—see 40 CFR 60.17) Class 2 (or better) tolerance weights. Audit the balance each day it is used for gravimetric measurements by weighing at least one ASTM E617–13 Class 2 tolerance (or better) calibration weight that corresponds to 50 to 150 percent of the weight of one filter or between 1g and 5g. If the scale cannot reproduce the value of the calibration weight to within 0.5 mg of the certified mass, perform corrective measures, and conduct the multipoint calibration before use." Method 30A §8.1 was revised by adding the following text to "[~~Sample Point~~] Selection of Sampling Sites and Sampling Points." Method 30B §8.1 was revised by adding the following text to "[~~Sample Point~~] Selection of Sampling Sites and Sampling Points. §8..3.3.8 was revised by adding the following text to "Therefore, procedures in ASTM [~~WK223~~] D6911-15 ''Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis'' (incorporated by reference-see 40 CFR 60.17) shall be followed for all samples, where appropriate." **81 Fed. Reg. 59800 (August 30, 2016)**
R307-221-4	Section 40 CFR Part 60.18	No Change
R307-222-2	40 CFR 60.31e	No Change
R307-222-2	40 CFR 60.51c	No Change

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Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
R307-222-3	40 CFR 60.52c(b), 40 CFR 60.53c, 40 CFR 60.55c, 40 CFR 60.58c(b) excluding (b)(2)(ii) and (b)(7), and 40 CFR 60.58c(c) through (f)	No Change
R307-222-4	Table 2 in 40 CFR Part 60, Subpart Ce (40CFR60.30e-39e)	No Change
R307-222-5(2)	40 CFR 60.36e(a)(1) and (a)(2)	No Change
R307-222-5(3)	Testing requirements of 40 CFR 60.37e(b)(1) through (b)(5)	No Change
R307-222-5(4)	40 CFR 60.37e(d)(1) through (d)(3)	No Change
R307-222-5(5)	40 CFR 60.38e(b)(1) and (b)(2)	No Change
R307-222-5(6)	40 CFR 60.1555(a) through (k)	No Change
R307-223-1(2)	40 CFR 60.1940	No Change
R307-223-2(1)	Equations found in 40 CFR 60.1935	No Change
R307-223-2(2)	40 CFR 60.1540 and 60.1585 through 60.1905, and with the requirements and schedules set forth in Tables 2 through 8 that are found following 40 CFR 60.1940 for operator training and certification	No Change

R307-101-3
Summary of Code of Federal Regulations Changes from July 1, 2016, to July 1, 2017

Rule	CFR Section Incorporated	Summary of Changes to Code of Federal Regulations
R307-223-3(1)	40 CFR Part 60, subpart HHHH, Sections 60.4101 through 60.4124; (b) Sections 60.4142 paragraph (c)(2) through paragraph (c)(4); (c) Sections 60.4150 through 60.4176	No Change
R307-224-2	Definitions contained in 40 CFR 93.101	No Change
R307-310-2	40 CFR Parts 63.421, 63.425(e), 63.425(i),	No Change
R307-328	40 CFR Parts 70, 72.2, 720.3(ee),	No Change
R307-415	40 CFR Part 72	No change
R307-417-1	40 CFR Part 75	No Change
R307-417-2	40 CFR Part 76	No Change
R307-417-3	40 CFR 763 Subpart E, and appendices	No Change
R307-801-4	40 CFR 763 Subpart E, and appendices	No Change

ITEM 6

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-084-17

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Rules Coordinator

DATE: December 19, 2017

SUBJECT: PROPOSE FOR PUBLIC COMMENT: R307-210. Standards of Performance for New Stationary Sources.

R307-210, Standards of Performance for New Stationary Sources (NSPS), must be updated periodically to reflect changes to federal air quality regulations found in Title 40 of the Code of Federal Regulations (40 CFR) Part 60. All published changes to 40 CFR Part 60 from July 1, 2016, to July 1, 2017, are listed in the attached document. To reflect these changes, R307-210 needs to be amended to incorporate by reference the July 1, 2017, version of 40 CFR Part 60.

Recommendation: Staff recommends that the Board propose the amended R307-210 for public comment.

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R307. Environmental Quality, Air Quality.
R307-210. Standards of Performance for New Stationary Sources.
R307-210-1. Standards of Performance for New Stationary Sources.

The provisions of 40 Code of Federal Regulations (CFR) Part 60, effective on July 1, 201[~~6~~]7, except for Subparts Cb, Cc, Cd, Ce, BBBB, DDDD, and HHHH, are incorporated by reference into these rules with the exception that references in 40 CFR to "Administrator" shall mean "director" unless by federal law the authority referenced is specific to the Administrator and cannot be delegated.

KEY: air pollution, stationary sources, new source review
Date of Enactment or Last Substantive Amendment: [~~June 8, 2017~~]2018
Notice of Continuation: May 12, 2016
Authorizing, and Implemented or Interpreted Law: 19-2-104(3)(q); 19-2-108

R307-210
Final Standards of Performance for Stationary Sources (NSPS) for Adoption From July 1, 2016, to July 1, 2016

CFR Reference	Summary of Changes to Code of Federal Regulations
40 CFR 61	No changes
40 CFR 60.17	Redesignated paragraphs (h)(185) through (h)(206) as (h)(186) through (h)(207) Added §60.17(h)(185): "ASTM D6522–11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved December 1, 2011), IBR approved for § 60.37f(a)." **81 Fed. Reg. 59313 (August 29, 2016)** §60.17(h)(185) was revised by amending the following text to "ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b), §60.766(a). **81 Fed. Reg. 59368 (August 29, 2016)** Redesignated paragraphs (h)(190) through (h)(199) as (h)(191) through (h)(200) Redesignated paragraphs (h)(200) through (h)(206) as (h)(202) through (h)(208) §60.17(h)(180) was revised by amending the following text to "…IBR approved for §60.73a(b), table 7 to subpart IIII, [~~and~~] table 2 to subpart JJJJ, and § 60.4245(d). Added §60.17(h)(190): "ASTM D6911–15, Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015, IBR approved for appendix A–8: Method 30B." Added §60.17(h)(201) "ASTM E617–13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A–3: Methods 4, 5, 5H, 5I, and appendix A–8: Method 29." **81 Fed. Reg. 59809 (August 30, 2016)** Redesignated paragraphs (h)(191) through (h)(202, (204), (205), and (207) as follows: (h)(191) to (h)(192) (h)(192) to (h)(193) (h)(193) to (h)(194) (h)(194) to (h)(195) (h)(195) to (h)(196) (h)(196) to (h)(197) (h)(197) to (h)(198)

R307-210
Final Standards of Performance for Stationary Sources (NSPS) for Adoption
From July 1, 2016, to July 1, 2016

CFR Reference	Summary of Changes to Code of Federal Regulations
	(h)(198) to (h)(199) (h)(199) to (h)(200) (h)(200) to (h)(201) (h)(201) to (h)(204) (h)(202) to (h)(209) (h)(204) to (h)(205) (h)(205) to (h)(207) (h)(207) to (h)(208) Added §60.17(h)(191): "ASTM D6911–15, Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015, IBR approved for appendix A–8: Method 30B." Added §60.17(h)(202): "ASTM E617–13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A–3: Methods 4, 5, 5H, 5I, and appendix A–8: Method 29." **82 Fed. Reg. 28562 (June 23, 2017)**
40 CFR 60.48Da (f)	No Changes
40 CFR 60.61-60.64	No Changes
40 CFR 60.100a-60.107a	§60.102a(f)(1)(i) was revised by amending the following text to "For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases containing SO_2 into the atmosphere [~~(SO2)~~] in excess of the emission limit calculated using Equation 1 of this section. …" **81 Fed. Reg. 45240 (July 13, 2016)**
40 CFR 60.200; 60.201; 60.203; 60.205; 60.210; 62.211; 60.213 60.215; 60.223-60.225; 60.230; 60.233; 60.235; 60.243; 60.245.	No Change
60.332; 60.543; 60.562-1; 60.614; 60.643; 60.664	No Change
40 CFR 60.2000-60.2265 (Subpart CCCC)	No Change
40 CFR 60.4300-60.4420 (Subpart KKKK)	No Change
40 CFR 60.5360-60.5499 (Subpart OOOO)	No Change

R307-210
Final Standards of Performance for Stationary Sources (NSPS) for Adoption From July 1, 2016, to July 1, 2016

CFR Reference	Summary of Changes to Code of Federal Regulations
40 CFR 60.5360a-60.5499a (Subpart OOOOa)	No Change
40 CFR 60.5508-60.5580 (Subpart TTTT)	No Change
40 CFR 60.5700-60.5880 (Subpart UUUU)	No Change
40 CFR 60. Appendix B	**Performance Specification 1** Added the entry "Performance Specification 16—Specifications and Test Procedures for Predictive Emission Monitoring Systems in Stationary Sources" to the table of contents. §8.1(2)(i) was revised by adding the following text to the end of the section: "Alternatively, you may select a measurement location specified in paragraph 8.1(2)(ii) or 8.1(2)(iii)." **Performance Specification 2** §3.11 was revised by amending the following text to "Span Value means the [~~concentration specified for the affected source category in an applicable subpart of the regulations that is used to set the calibration gas concentration and in determining calibration drift.~~] calibration portion of the measurement range as specified in the applicable regulation or other requirement. If the span is not specified in the applicable regulation or other requirement, then it must be a value approximately equivalent to two times the emission standard. For spans less than 500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm such that the equivalent emission concentration is not less than 30 percent of the selected span value." §6.1.1 was revised by amending the following text to "Data Recorder[~~ Scale~~]. The portion of the CEMS [~~data recorder~~] that provides a record of analyzer output. [~~range must include zero and a high-level value. The high-level value is chosen by the source owner or operator and is defined as follows:~~] The data recorder may record other pertinent data such as effluent flow rates, various instrument temperatures or abnormal CEMS operation. The data recorder output range must include the full range of expected concentration values in the gas stream to be sampled including zero and span values." §6.1.2 was revised by amending the following text to "The CEMS design should also allow the determination of calibration drift at the zero and [~~high-level~~] span values. If this is not possible or practical, the design must allow these determinations to be conducted at a low-level value (zero to 20 percent of the [~~high-level~~] span

R307-210
Final Standards of Performance for Stationary Sources (NSPS) for Adoption From July 1, 2016, to July 1, 2016

CFR Reference	Summary of Changes to Code of Federal Regulations
	value) and at a value between 50 and 100 percent of the high-level value. In special cases, the Administrator may approve a single-point calibration[-]_drift determination." §16.3.2 changes the equation shown from [$\cancel{RA = \lvert\bar{d}\rvert \leq 0.7 \text{ percent } O_2 \text{ or } CO_2}$] to $\underline{RA \equiv d; \leq 0.7 \text{ percent } O_2 \text{ or } CO_2}$ §18.0 updates Figure 2-1 and Figure 2-2. **Performance Specification 3** §13.2 was revised by amending the following text to "CEMS Relative Accuracy Performance Specification. The RA of the CEMS must be no greater than 20.0 percent of the mean value of the reference method (RM) data when calculated using equations 3-1." Additionally, §13.2 also adds Eq. 3-1 and Eq. 3-2. **Performance Specification 4A** §8.3 was revised by amending the following text to "Response Time Test Procedure. The response time test applies to all types of CEMS, but will generally have significance only for extractive systems. The entire system is checked with this procedure including applicable sample extraction and transport, sample conditioning, gas analyses, and data recording." §8.3.1 was revised by amending the following text to "Introduce zero gas into the [~~analyzer~~] system. … Repeat the entire procedure [~~three times and~~] until you have three sets of data to determine the mean upscale and downscale response times." §8.3.1 was revised by amending the following text to "Response Time. The CEMS response time shall not exceed [~~1.5 min~~] 240 seconds to achieve 95 percent of the final stable value." **Performance Specification 11** §16.3.2 changes the equation and corresponding definitions shown in Eq. 11-1 from [$\cancel{UD = \frac{\lvert R_{CEM} - R_U \rvert}{FS} \times 100}$] to $UD = \frac{\lvert R_{CEM} - R_U \rvert}{R_r} \times 100$. Additionally, §16.3.2 changes the equation and corresponding definitions shown in Eq. 11-2 from [$\cancel{ZD = \frac{\lvert R_{CEM} - R_L \rvert}{FS} \times 100}$] to $ZD = \frac{\lvert R_{CEM} - R_L \rvert}{R_r} \times 100$.

R307-210
Final Standards of Performance for Stationary Sources (NSPS) for Adoption From July 1, 2016, to July 1, 2016

CFR Reference	Summary of Changes to Code of Federal Regulations
	§13.1 was revised by amending the following text to "What is the 7-day drift check performance specification? Your daily PM CEMS internal drift checks must demonstrate that the average daily drift of your PM CEMS does not deviate from the value of the reference light, optical filter, Beta attenuation signal, or other technology-suitable reference standard by more than 2 percent of the [~~upscale value~~] response range…" **Performance Specification 15** §9.1.2 was revised by amending the following text to "Test Procedure. [~~An audit sample is obtained from the Administrator.~~] Spike the audit …" The following sections were reserved: §14.0 Pollution Prevention [Reserved] §15.0 Waste Management [Reserved] **Performance Specification 16** §17.0 updates Table 16-1 **81 Fed. Reg. 59819 (August 30, 2016)**

ITEM 7

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-086-17

MEMORANDUM

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Rules Coordinator

DATE: December 19, 2017

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-214. National Emission Standards for Hazardous Air Pollutants.

R307-214, National Emission Standards for Hazardous Air Pollutants (NESHAPs), must be updated periodically to reflect changes to the NESHAPs as published in Title 40 of the Code of Federal Regulations (40 CFR) Parts 61 and 63.

All published changes to 40 CFR Parts 61 and 63 from July 1, 2016, to July 1, 2017, are listed in the attached document. To reflect these changes, R307-214 was amended to incorporate by reference the July 1, 2017, version of 40 CFR Parts 61 and 63.

Recommendation: Staff recommends that the Board propose the amended R307-214 for public comment.

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R307. Environmental Quality, Air Quality.

R307-214. National Emission Standards for Hazardous Air Pollutants.

R307-214-1. Pollutants Subject to Part 61.

The provisions of Title 40 of the Code of Federal Regulations (40 CFR) Part 61, National Emission Standards for Hazardous Air Pollutants, effective as of July 1, 201[~~6~~]7, are incorporated into these rules by reference. For pollutant emission standards delegated to the State, references in 40 CFR Part 61 to "the Administrator" shall refer to the director.

R307-214-2. Sources Subject to Part 63.

The provisions listed below of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories, effective as of July 1, 201[~~6~~]7, are incorporated into these rules by reference. References in 40 CFR Part 63 to "the Administrator" shall refer to the director, unless by federal law the authority is specific to the Administrator and cannot be delegated.

(1) 40 CFR Part 63, Subpart A, General Provisions.

(2) 40 CFR Part 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with 42 U.S.C. 7412(g) and (j).

(3) 40 CFR Part 63, Subpart F, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry.

(4) 40 CFR Part 63, Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater.

(5) 40 CFR Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks.

(6) 40 CFR Part 63, Subpart I, National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks.

(7) 40 CFR Part 63, Subpart J, National Emission Standards for Polyvinyl Chloride and Copolymers Production.

(8) 40 CFR Part 63, Subpart L, National Emission Standards for Coke Oven Batteries.

(9) 40 CFR Part 63, Subpart M, National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities.

(10) 40 CFR Part 63, Subpart N, National Emission Standards for Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks.

(11) 40 CFR Part 63, Subpart O, National Emission Standards for Hazardous Air Pollutants for Ethylene Oxide Commercial Sterilization and Fumigation Operations.

(12) 40 CFR Part 63, Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.

(13) 40 CFR Part 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

(14) 40 CFR Part 63, Subpart T, National Emission Standards for Halogenated Solvent Cleaning.

(15) 40 CFR Part 63, Subpart U, National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins.

(16) 40 CFR Part 63, Subpart AA, National Emission Standards for Hazardous Air Pollutants for Phosphoric Acid Manufacturing.

(17) 40 CFR Part 63, Subpart BB, National Emission Standards for Hazardous Air Pollutants for Phosphate Fertilizer Production.

(18) 40 CFR Part 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

(19) 40 CFR Part 63, Subpart DD, National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations.

(20) 40 CFR Part 63, Subpart EE, National Emission Standards for Magnetic Tape Manufacturing Operations.

(21) 40 CFR Part 63, Subpart GG, National Emission Standards for Aerospace Manufacturing and Rework Facilities.

(22) 40 CFR Part 63, Subpart HH, National Emission Standards for Hazardous Air Pollutants for Oil and Natural Gas Production.

(23) 40 CFR Part 63, Subpart JJ, National Emission Standards for Wood Furniture Manufacturing Operations.

(24) 40 CFR Part 63, Subpart KK, National Emission Standards for the Printing and Publishing Industry.

(25) 40 CFR Part 63, Subpart MM, National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills.

(26) 40 CFR Part 63, Subpart OO, National Emission Standards for Tanks - Level 1.

(27) 40 CFR Part 63, Subpart PP, National Emission Standards for Containers.

(28) 40 CFR Part 63, Subpart QQ, National Emission Standards for Surface Impoundments.

(29) 40 CFR Part 63, Subpart RR, National Emission Standards for Individual Drain Systems.

(30) 40 CFR Part 63, Subpart SS, National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process (Generic MACT).

(31) 40 CFR Part 63, Subpart TT, National Emission Standards for Equipment Leaks- Control Level 1 (Generic MACT).

(32) 40 CFR Part 63, Subpart UU, National Emission Standards for Equipment Leaks-Control Level 2 Standards (Generic MACT).

(33) 40 CFR Part 63, Subpart VV, National Emission Standards for Oil-Water Separators and Organic-Water Separators.

(34) 40 CFR Part 63, Subpart WW, National Emission Standards for Storage Vessels (Tanks)-Control Level 2 (Generic MACT).

(35) 40 CFR Part 63, Subpart XX, National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations.

(36) 40 CFR Part 63, Subpart YY, National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic MACT.

(37) 40 CFR Part 63, Subpart CCC, National Emission Standards for Hazardous Air Pollutants for Steel Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants.

(38) 40 CFR Part 63, Subpart DDD, National Emission Standards

for Hazardous Air Pollutants for Mineral Wool Production.

(39) 40 CFR Part 63, Subpart EEE, National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors.

(40) 40 CFR Part 63, Subpart GGG, National Emission Standards for Hazardous Air Pollutants for Pharmaceuticals Production.

(41) 40 CFR Part 63, Subpart HHH, National Emission Standards for Hazardous Air Pollutants for Natural Gas Transmission and Storage.

(42) 40 CFR Part 63, Subpart III, National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production.

(43) 40 CFR Part 63, Subpart JJJ, National Emission Standards for Hazardous Air Pollutants for Group IV Polymers and Resins.

(44) 40 CFR Part 63, Subpart LLL, National Emission Standards for Hazardous Air Pollutants for Portland Cement Manufacturing Industry.

(45) 40 CFR Part 63, Subpart MMM, National Emission Standards for Hazardous Air Pollutants for Pesticide Active Ingredient Production.

(46) 40 CFR Part 63, Subpart NNN, National Emission Standards for Hazardous Air Pollutants for Wool Fiberglass Manufacturing.

(47) 40 CFR Part 63, Subpart OOO, National Emission Standards for Hazardous Air Pollutants for Amino/Phenolic Resins Production (Resin III).

(48) 40 CFR Part 63, Subpart PPP, National Emission Standards for Hazardous Air Pollutants for Polyether Polyols Production.

(49) 40 CFR Part 63, Subpart QQQ, National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelters.

(50) 40 CFR Part 63, Subpart RRR, National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production.

(51) 40 CFR Part 63, Subpart TTT, National Emission Standards for Hazardous Air Pollutants for Primary Lead Smelting.

(52) 40 CFR Part 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(53) 40 CFR Part 63, Subpart VVV, National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works.

(54) 40 CFR Part 63, Subpart AAAA, National Emission Standards for Hazardous Air Pollutants for Municipal Solid Waste Landfills.

(55) 40 CFR Part 63, Subpart CCCC, National Emission Standards for Manufacturing of Nutritional Yeast.

(56) 40 CFR Part 63, Subpart DDDD, National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products.

(57) 40 CFR Part 63, Subpart EEEE, National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution (non-gasoline).

(58) 40 CFR Part 63, Subpart FFFF, National Emission Standards for Hazardous Air Pollutants for Miscellaneous Organic Chemical Manufacturing.

(59) 40 CFR Part 63, Subpart GGGG, National Emission Standards for Vegetable Oil Production; Solvent Extraction.

(60) 40 CFR Part 63, Subpart HHHH, National Emission Standards for Wet-Formed Fiberglass Mat Production.

(61) 40 CFR Part 63, Subpart IIII, National Emission Standards for Hazardous Air Pollutants for Surface Coating of Automobiles and Light-Duty Trucks.

(62) 40 CFR Part 63, Subpart JJJJ, National Emission Standards for Hazardous Air Pollutants for Paper and Other Web Surface Coating Operations.

(63) 40 CFR Part 63, Subpart KKKK, National Emission Standards for Hazardous Air Pollutants for Surface Coating of Metal Cans.

(64) 40 CFR Part 63, Subpart MMMM, National Emission Standards for Hazardous Air Pollutants for Surface Coating of Miscellaneous Metal Parts and Products.

(65) 40 CFR Part 63, Subpart NNNN, National Emission Standards for Large Appliances Surface Coating Operations.

(66) 40 CFR Part 63, Subpart OOOO, National Emission Standards for Hazardous Air Pollutants for Fabric Printing, Coating and Dyeing Surface Coating Operations.

(67) 40 CFR Part 63, Subpart PPPP, National Emissions Standards for Hazardous Air Pollutants for Surface Coating of Plastic Parts and Products.

(68) 40 CFR Part 63, Subpart QQQQ, National Emission Standards for Hazardous Air Pollutants for Surface Coating of Wood Building Products.

(69) 40 CFR Part 63, Subpart RRRR, National Emission Standards for Hazardous Air Pollutants for Metal Furniture Surface Coating Operations.

(70) 40 CFR Part 63, Subpart SSSS, National Emission Standards for Metal Coil Surface Coating Operations.

(71) 40 CFR Part 63, Subpart TTTT, National Emission Standards for Leather Tanning and Finishing Operations.

(72) 40 CFR Part 63, Subpart UUUU, National Emission Standards for Cellulose Product Manufacturing.

(73) 40 CFR Part 63, Subpart VVVV, National Emission Standards for Boat Manufacturing.

(74) 40 CFR Part 63, Subpart WWWW, National Emissions Standards for Hazardous Air Pollutants for Reinforced Plastic Composites Production.

(75) 40 CFR Part 63, Subpart XXXX, National Emission Standards for Tire Manufacturing.

(76) 40 CFR Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

(77) 40 CFR Part 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

(78) 40 CFR Part 63, Subpart AAAAA, National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants.

(79) 40 CFR Part 63, Subpart BBBBB, National Emission Standards for Hazardous Air Pollutants for Semiconductor Manufacturing.

(80) 40 CFR Part 63, Subpart CCCCC, National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks.

(81) 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and

Institutional Boilers and Process Heaters.

(82) 40 CFR Part 63, Subpart EEEEE, National Emission Standards for Hazardous Air Pollutants for Iron and Steel Foundries.

(83) 40 CFR Part 63, Subpart FFFFF, National Emission Standards for Hazardous Air Pollutants for Integrated Iron and Steel Manufacturing.

(84) 40 CFR Part 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants for Site Remediation.

(85) 40 CFR Part 63, Subpart HHHHH, National Emission Standards for Hazardous Air Pollutants for Miscellaneous Coating Manufacturing.

(86) 40 CFR Part 63, Subpart IIIII, National Emission Standards for Hazardous Air Pollutants for Mercury Emissions from Mercury Cell Chlor-Alkali Plants.

(87) 40 CFR Part 63, Subpart JJJJJ, National Emission Standards for Hazardous Air Pollutants for Brick and Structural Clay Products Manufacturing.

(88) 40 CFR Part 63, Subpart KKKKK, National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing.

(89) 40 CFR Part 63, Subpart LLLLL, National Emission Standards for Hazardous Air Pollutants for Asphalt Processing and Asphalt Roofing Manufacturing.

(90) 40 CFR Part 63, Subpart MMMMM, National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Fabrication Operations.

(91) 40 CFR Part 63, Subpart NNNNN, National Emission Standards for Hazardous Air Pollutants for Hydrochloric Acid Production.

(92) 40 CFR Part 63, Subpart PPPPP, National Emission Standards for Hazardous Air Pollutants for Engine Test Cells/Stands.

(93) 40 CFR Part 63, Subpart QQQQQ, National Emission Standards for Hazardous Air Pollutants for Friction Materials Manufacturing Facilities.

(94) 40 CFR Part 63, Subpart RRRRR, National Emission Standards for Hazardous Air Pollutants for Taconite Iron Ore Processing.

(95) 40 CFR Part 63, Subpart SSSSS, National Emission Standards for Hazardous Air Pollutants for Refractory Products Manufacturing.

(96) 40 CFR Part 63, Subpart TTTTT, National Emission Standards for Hazardous Air Pollutants for Primary Magnesium Refining.

(97) 40 CFR Part 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units.

(98) 40 CFR Part 63, Subpart WWWWW, National Emission Standards for Hospital Ethylene Oxide Sterilizers.

(99) 40 CFR Part 63, Subpart YYYYY, National Emission Standards for Hazardous Air Pollutants for Area Sources: Electric Arc Furnace Steelmaking Facilities.

(100) 40 CFR Part 63, Subpart ZZZZZ, National Emission Standards for Hazardous Air Pollutants for Iron and Steel Foundries Area Sources.

(101) 40 CFR Part 63 Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

(102) 40 CFR Part 63 Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing

Facilities.

(103) 40 CFR Part 63, Subpart DDDDDD, National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production Area Sources.

(104) 40 CFR Part 63, Subpart EEEEEE, National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting Area Sources.

(105) 40 CFR Part 63, Subpart FFFFFF, National Emission Standards for Hazardous Air Pollutants for Secondary Copper Smelting Area Sources.

(106) 40 CFR Part 63, Subpart GGGGGG, National Emission Standards for Hazardous Air Pollutants for Primary Nonferrous Metals Area Sources--Zinc, Cadmium, and Beryllium.

(107) 40 CFR Part 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources.

(108) 40 CFR Part 63, Subpart LLLLLL, National Emission Standards for Hazardous Air Pollutants for Acrylic and Modacrylic Fibers Production Area Sources.

(109) 40 CFR Part 63, Subpart MMMMMM, National Emission Standards for Hazardous Air Pollutants for Carbon Black Production Area Sources.

(110) 40 CFR Part 63, Subpart NNNNNN, National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources: Chromium Compounds.

(111) 40 CFR Part 63, Subpart OOOOOO, National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production and Fabrication Area Sources.

(112) 40 CFR Part 63, Subpart PPPPPP, National Emission Standards for Hazardous Air Pollutants for Lead Acid Battery Manufacturing Area Sources.

(113) 40 CFR Part 63, Subpart QQQQQQ, National Emission Standards for Hazardous Air Pollutants for Wood Preserving Area Sources.

(114) 40 CFR Part 63, Subpart RRRRRR, National Emission Standards for Hazardous Air Pollutants for Clay Ceramics Manufacturing Area Sources.

(115) 40 CFR Part 63, Subpart SSSSSS, National Emission Standards for Hazardous Air Pollutants for Glass Manufacturing Area Sources.

(116) 40 CFR Part 63, Subpart VVVVVV, National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources.

(117) 40 CFR Part 63, Subpart TTTTTT, National Emission Standards for Hazardous Air Pollutants for Secondary Nonferrous Metals Processing Area Sources.

(118) 40 CFR Part 63, Subpart WWWWWW, National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations.

(119) 40 CFR Part 63, Subpart XXXXXX, National Emission Standards for Hazardous Air Pollutants Area Source Standards for Nine Metal Fabrication and Finishing Source Categories.

(120) 40 CFR Part 63, Subpart YYYYYY, National Emission Standards for Hazardous Air Pollutants for Area Sources: Ferroalloys Production Facilities.

(121) 40 CFR Part 63, Subpart ZZZZZZ, National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Aluminum, Copper, and Other Nonferrous Foundries.

(122) 40 CFR Part 63, Subpart AAAAAAA, National Emission Standards for Hazardous Air Pollutants for Area Sources: Asphalt Processing and Asphalt Roofing Manufacturing.

(123) 40 CFR Part 63, Subpart BBBBBBB, National Emission Standards for Hazardous Air Pollutants for Area Sources: Chemical Preparations Industry.

(124) 40 CFR Part 63, Subpart CCCCCCC, National Emission Standards for Hazardous Air Pollutants for Area Sources: Paints and Allied Products Manufacturing.

(125) 40 CFR Part 63, Subpart DDDDDDD, National Emission Standards for Hazardous Air Pollutants for Area Sources: Prepared Feeds Manufacturing.

(126) 40 CFR Part 63, Subpart EEEEEEE, National Emission Standards for Hazardous Air Pollutants: Gold Mine Ore Processing and Production Area Source Category.

KEY: air pollution, hazardous air pollutant, MACT, NESHAP
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40 CFR 61	§61.13(e)(1)(i) was revised by amending the following text to "The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A–3 of part 60 of this chapter; Methods 6C, 7E, 9, and 10 of appendix A–4 of part 60; Method 18 and 19 of appendix A–6 of part 60; Methods 20, 22, and 25A of appendix A–7 of part 60; Methods 30A and 30B of appendix A–8 of part 60; and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter..." **81 Fed. Reg. 59825 (August 30, 2016)** §61.251 was revised by amending the following paragraphs: "(b) Continuous disposal means a method of uranium byproduct material or tailings management and disposal in which uranium byproduct material or tailings are dewatered by mechanical methods immediately after generation. The dried uranium byproduct material or tailings are then placed in trenches or other disposal areas and immediately covered to limit emissions consistent with applicable Federal standards. (c) Dewatered means to remove the water from recently produced uranium byproduct material or tailings by mechanical or evaporative methods such that the water content of the uranium byproduct material or tailings does not exceed 30 percent by weight. (d) Existing impoundment means any conventional uranium [~~mill~~] byproduct material or tailings impoundment which is licensed to accept additional uranium byproduct material or tailings and is in existence as of December 15, 1989. (e) Operation. Operation means that an impoundment is being used for the continued placement of [~~new~~] uranium byproduct material or tailings or is in standby status for such placement. An impoundment is in operation from the day that uranium byproduct material or tailings are first placed in the impoundment until the day that final closure begins. (f) Phased disposal means a method of uranium byproduct material or tailings management and disposal which uses lined impoundments which are filled and then immediately dried and covered to meet all applicable Federal standards." §61.251 was also revised by adding the following paragraphs: "(h) Conventional impoundment. A conventional impoundment is a permanent structure located at any uranium recovery facility which contains mostly solid uranium byproduct material or tailings from the extraction of uranium from uranium ore. These impoundments are left in place at facility closure. (i) Non-conventional impoundment. A non-conventional impoundment is used for managing liquids from uranium recovery operations and contains uranium byproduct material or tailings suspended in and/or covered by liquids. These structures are commonly known as holding ponds or evaporation ponds and can be located at any uranium recovery facility. They are typically not permanent structures unless they transition to become used as conventional impoundments. Impoundments constructed for the purpose of managing liquids from closure or remediation activities (e.g., contaminated groundwater), and which are used solely for that purpose, are not subject to the requirements of this subpart. (j) Heap leach pile. A heap leach pile is a pile of uranium ore placed on an engineered structure and stacked so as to allow uranium to be dissolved and removed by leaching liquids. (k) Standby. Standby means the period of time that an impoundment is not accepting uranium byproduct material or tailings but has

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	not yet entered final closure. (l) Uranium recovery facility. A uranium recovery facility means a facility licensed by the NRC or an NRC Agreement State to manage uranium byproduct material or tailings during and following the processing of uranium ores. Common names for these facilities are a conventional uranium mill, an insitu leach (or recovery) facility and a heap leach facility or pile. (m) Heap leach pile operational life. The operational life of a heap leach pile means the time period from the first time that lixiviant is placed on the heap leach pile until the time the final rinse is completed. (n) Final closure means the period during which an impoundment or heap leach pile is being managed in accordance with the milestones and requirements in an approved reclamation plan. Final closure for the impoundment or heap leach pile begins when the owner or operator provides written notice to the Administrator and to the Nuclear Regulatory Commission or applicable NRC Agreement State that: (1) A conventional impoundment is no longer receiving uranium byproduct material or tailings, is no longer on standby for such receipt and is being managed under an approved reclamation plan for that impoundment or facility closure plan; or (2) A non-conventional impoundment is no longer required for evaporation or holding purposes, is no longer on standby for such purposes and is being managed under an approved reclamation plan for that impoundment or facility closure plan; or (3) A heap leach pile has concluded its operational life and is being managed under an approved reclamation plan for that pile or facility closure plan. (o) Reclamation plan means the plan detailing activities and milestones to accomplish reclamation of impoundments or piles containing uranium byproduct material or tailings. Activities and milestones to be addressed include, but are not limited to, dewatering and contouring of conventional impoundments and heap leach piles, and removal and disposal of non-conventional impoundments. A reclamation plan prepared and approved in accordance with 10 CFR part 40, Appendix A is considered a reclamation plan in this subpart." §61.252 was revised by amending the following paragraphs: "(a) Each owner or operator of a conventional impounding shall comply with the following requirements: (1) Radon-222 emissions to the ambient air from an existing [~~uranium mill tailings pile~~] conventional impoundment shall not exceed 20 pCi/ (m2-sec) (1.9 pCi/(ft2-sec)) of radon-222 and all owners or operators shall comply with the provisions of 40 CFR 192.32(a)(1). [~~(b)~~](2) After December 15, 1989, no new [~~tailings~~] conventional impoundment [~~can~~] may be built unless it is designed, constructed and operated to meet one of the two following [~~work~~] management practices: [~~(1)~~](i) Phased disposal in lined [~~tailings~~] impoundments that are no more than 40 acres in area and [~~meet~~] comply with the requirements of 40 CFR 192.32(a)(1) [~~as determined by the Nuclear Regulatory Commission~~]. The owner or operator shall have no more than two conventional impoundments, including existing conventional impoundments, in operation at any one time. [~~(2)~~](ii) Continuous disposal [~~of tailings~~] such that uranium byproduct material or tailings are dewatered and immediately disposed with no more than 10 acres uncovered at any time and [~~operated in accordance~~] shall comply with the requirements of [§]40 CFR 192.32(a)(1).[~~as determined by the Nuclear Regulatory Commission.~~] [~~(c)~~](b) [~~All mill owners or operators~~] Each owner or operator of a non-conventional impoundment shall comply with the

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	[~~provisions of 40 CFR 192.32(a) in the operation of tailings piles, the exemption for existing piles in 40 CFR 192.32(a) notwithstanding.~~] following requirements: Non-conventional impoundments shall meet the requirements of 40 CFR 192.32(a)(1). During operation and until final closure begins, the liquid level in the impoundment shall be maintained so that solid materials in the impoundment are not visible above the liquid surface, verified by daily inspections documented through notations and by digital photographic evidence collected at least weekly. Should inspection reveal that solid materials in the impoundment are visible above the liquid surface, the owner or operator must correct the situation within seven days, or other such time as specified by the Administrator. (c) Each owner or operator of a heap leach pile shall comply with the following requirements: Heap leach piles that have completed their operating life but have not yet entered final closure shall be managed in compliance with the phased disposal management practice in paragraph (a)(2)(i) of this section. Heap leach piles shall be constructed in lined impoundments that are no more than 40 acres in area and shall comply with the requirements of 40 CFR 192.32(a)(1). The owner or operator shall have no more than two heap leach piles, including existing heap leach piles, subject to this subpart at any one time." [~~[54 FR 51703, Dec. 15, 1989, as amended at 65 FR 62159, Oct. 17, 2000]~~] §61.255 was revised by amending and adding the following paragraphs: "(a) The owner or operator of [~~the mill~~] any uranium recovery facility must maintain records [~~documenting the source of input parameters including the results of all measurements upon which they are based, the calculations and/or analytical methods used to derive values for input parameters, and the procedure used to determine compliance. In addition, the documentation should be sufficient to allow an independent auditor to verify the accuracy of the determination made concerning the facility's compliance with the standard. These records must be kept at the mill for at least five years and upon request be made available for inspection by the Administrator, or his authorized representative.~~] that confirm that the conventional impoundment(s), nonconventional impoundment(s) and heap leach pile(s) subject to this subpart at the facility meet the requirements in 40 CFR 192.32(a)(1). These records shall include, but not be limited to, the results of liner compatibility tests. (b) The owner or operator of any uranium recovery facility with nonconventional impoundments must maintain written records from daily inspections and other records confirming that any sediments have remained saturated in the nonconventional impoundments at the facility. Periodic digital photographic evidence, with embedded date stamp and other identifying metadata, shall be collected no less frequently than weekly to demonstrate compliance with the requirements of § 61.252(b). Should inspection reveal that a nonconventional impoundment is not in compliance with the requirements of § 61.252(b), the owner or operator shall collect photographic evidence before and after the non-compliance is corrected. (c) The records required in paragraphs (a) and (b) in this section must be kept at the uranium recovery facility for the operational life of the facility and must be made available for inspection by the Administrator, or his authorized representative. (1) Digital photographs taken to demonstrate compliance with the requirements of § 61.252(c) shall be submitted electronically using the Subpart W Impoundment Photographic Reporting (SWIPR) system that is accessed through EPA's Central Data Exchange (CDX) (cdx.epa.gov) at least monthly. (i) Owners and operators must also submit information identifying the facility and facility location, the name or other designation of each impoundment, and the date and time of each photograph.

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	(ii) If the reporting form specific to this subpart is not available in SWIPR, the owner or operator must retain the digital photographs at the facility and provide them to the EPA or authorized State upon request, with the supporting information required in paragraph (c)(1)(i) of this section. (2) [Reserved]" **82 Fed. Reg. 5178 (January 17, 2017)** §61.04(c)(9) updated the tables found at subparagraph (i) and (iv). **82 Fed. Reg. 21933 (May 11, 2017)**
40 CFR 63.600-63.611 (Subpart AA)	No Changes
63.620--63.632 (Subpart BB)	No Changes
40 CFR 63.640-63.679 (Subpart CC)	§63.641 revised the definitions by amending the following: *Closed blowdown system* means a system used for depressuring process vessels that is not open to the atmosphere and is configured of piping, ductwork, connections, accumulators/knockout drums, and, if necessary, flow inducing devices that transport gas or vapor from a process vessel to a control device or back into the process. *Force majeure event* means a release of HAP, either directly to the atmosphere from a [~~relief valve~~] pressure relief device or discharged via a flare, that is demonstrated to the satisfaction of the Administrator to result from an event beyond the refinery owner or operator's control, such as natural disasters; acts of war or terrorism; loss of a utility external to the refinery (e.g., external power curtailment), excluding power curtailment due to an interruptible service agreement; and fire or explosion originating at a near or adjoining facility outside of the refinery [~~owner or operator's control~~] that impacts the refinery's ability to operate. *Miscellaneous process vent* (5) In situ sampling systems (onstream analyzers) until [~~January 30, 2019~~] February 1, 2016. After this date, these sampling systems will be included in the definition of miscellaneous process vents and sampling systems determined to be Group 1 miscellaneous process vents must comply with the requirements in §§ 63.643 and 63.644 no later than January 30, 2019; §63.643 was revised by amending paragraph (c) and adding paragraph (d): "(c) An owner or operator may designate a process vent as a maintenance vent if the vent is only used as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service. The owner [~~of~~] or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. The owner [~~or~~] of operator must comply with the applicable requirements in paragraphs (c)(1) through (3) of this section for each maintenance vent according to the compliance dates specified in table 11 of this subpart, unless an extension is requested in accordance with the provisions in § 63.6(i)."

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	"(d) After February 1, 2016 and prior to the date of compliance with the maintenance vent provisions in paragraph (c) of this section, the owner or operator must comply with the requirements in § 63.642(n) for each maintenance venting event and maintain records necessary to demonstrate compliance with the requirements in § 63.642(n) including, if appropriate, records of existing standard site procedures used to deinventory equipment for safety purposes." §63.648 was revised by amending the following text to "Each owner or operator of an existing source subject to the provisions of this subpart shall comply with the provisions of 40 CFR part 60, subpart VV, and paragraph (b) of this section except as provided in paragraphs (a)(1)[~~,~~] and [~~(a)~~](2), [~~and~~](c) through (i), and (j)(1) and (2) of this section. Each owner or operator of a new source subject to the provisions of this subpart shall comply with subpart H of this part except as provided in paragraphs (c) through (i) and (j)(1) and (2) of this section." §63.655(h)(8) was revised by amending the following text to "For fenceline monitoring systems subject to §63.658, within 45 calendar days after the end of each [~~quarterly~~]reporting period[~~ covered by the periodic report~~], each owner or operator shall submit the following information to the EPA's Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The owner or operator need not transmit this data prior to obtaining 12 months of data." §63.658 was revised by amending the following text to "As it pertains to this subpart, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of appendix A of this part for siting passive monitors means a wastewater treatment unit, process unit, or any emission source requiring control according to the requirements of this subpart, including marine vessel loading operations. For marine loading operations[~~ that are located offshore~~], one passive monitor should be sited on the shoreline adjacent to the dock." §63.658(o)(1) was revised by amending the following text to: "(ii)(B) Implementation of prevention measures listed for pressure relief devices in §63.648(j)(5) for each pressure relief [~~valve~~] device that can discharge to the flare." Additionally, "(vi) For each pressure relief [~~valve~~] device vented to the flare identified in paragraph (o)(1)(iv) of this section, provide a detailed description of each pressure release [~~valve~~] device, including type of relief device (rupture disc, valve type) diameter of the relief [~~valve~~] device opening, set pressure of the relief [~~valve~~] device and listing of the prevention measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the flare management plan unless requested to do so by the Administrator." The appendix to subpart CC was amended by revising Table 11. **81 Fed. Reg. 45240 (July 13, 2016)**
40 CFR 63.1175--63.1199 (Subpart DDD)	No Changes

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63.7480--63.7575 (Subpart DDDDD)	No Changes
40 CFR 63.741-63.759 (Subpart GG)	§63.749(a)(3) was revised by amending the following text "Each owner or operator of a specialty coating application operation or handling and storage of waste operation that begins construction or reconstruction after February 17, 2015 shall be in compliance with the requirements of this subpart on December 7, 2015 or upon startup, whichever is later. Each owner or operator of a specialty coating application operation or handling and storage of waste operation that is existing on February 17, 2015 shall be in compliance with the requirements of this subpart on or before December 7, 2018." **81 Fed. Reg. 51116 (August 3, 2016)**
63.8380--63.8515 (Subpart JJJJJ)	No Changes
63.8530--63.8665 (Subpart KKKKK)	No Changes
40 CFR 63.1340--63.1359 (Subpart LLL)	§61.1349(b)(6)(v) was revised by adding the following paragraphs: "As an alternative to paragraph (b)(6)(ii) of this section, the owner or operator may demonstrate initial compliance by conducting a performance test using Method 321 of appendix A to this part. You must also monitor continuous performance through use of an HCl CPMS according to paragraphs (b)(6)(v)(A) through (H) of this section. For kilns with inline raw mills, compliance testing and monitoring HCl to establish the site specific operating limit must be conducted during both raw mill on and raw mill off conditions. (A) For your HCl CPMS, you must establish a 30 kiln operating day sitespecific operating limit. If your HCl performance test demonstrates your HCl emission levels to be less than 75 percent of your emission limit (2.25 ppmvd @7% O2), you must use the time weighted average HCl CPMS indicated value recorded during the HCl compliance test (typically measured as ppmvw HCl at stack O2 concentration, but a dry, oxygen corrected value would also suffice), your HCl instrument zero output value, and the time weighted average HCl result of your compliance test to establish your operating limit. If your HCl compliance test demonstrates your HCl emission levels to be at or above 75 percent of your emission limit (2.25 ppmvd @7% O2), you must use the time weighted average HCl CPMS indicated value recorded during the HCl compliance test as your operating limit. You must use the HCl CPMS indicated signal data to demonstrate continuous compliance with your operating limit. (1) Your HCl CPMS must provide a ppm HCl concentration output and the establishment of its relationship to manual reference method measurements must be determined in units of indicated ppm. The instrument signal may be in ppmvw or ppmvd and the signal may be a measurement of HCl at in-stack concentration or a corrected oxygen concentration. Once the relationship between the indicated output of the HCl CPMS and the reference method test results is established, the HCl CPMS instrument measurement basis (ppmvw or ppmvd, or oxygen correction basis) must not be altered. Likewise, any setting that impacts the HCl CPMS indicated HCl response must remain fixed after the site-specific operating limit is set. (2) Your HCl CPMS operating range must be capable of reading HCl concentrations from zero to a level equivalent to 125 percent of the highest expected value during mill off operation. If your HCl CPMS is an autoranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading an indicated HCl concentration from zero to 10 ppm. (3) During the initial performance test of a kiln with an inline raw mill, or any such subsequent performance test that demonstrates

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	compliance with the HCl limit, record and average the indicated ppm HCl output values from the HCl CPMS for each of the six periods corresponding to the compliance test runs (e.g., average each of your HCl CPMS output values for six corresponding Method 321 test runs). With the average values of the six test runs, calculate the average of the three mill on test runs and the average of the three mill off test runs. Calculate the time weighted result using the average of the three mill on tests and the average of the three mill off tests and the previous annual ratio of mill on/mill off operations. Kilns without an inline raw mill will conduct three compliance tests and calculate the average monitor output values corresponding to these three test runs and not use time weighted values to determine their site specific operating limit. (B) Determine your operating limit as specified in paragraphs (b)(6)(i) or (iii) of this section. If your HCl performance test demonstrates your HCl emission levels to be below 75 percent of your emission limit, kilns with inline raw mills will use the time weighted average indicated HCl ppm concentration CPMS value recorded during the HCl compliance test, the zero value output from your HCl CPMS, and the time weighted average HCl result of your compliance test to establish your operating limit. Kilns without inline raw mills will not use a time weighted average value to establish their operating limit. If your time weighted HCl compliance test demonstrates your HCl emission levels to be at or above 75 percent of your emission limit, you will use the time weighted HCl CPMS indicated ppm value recorded during the HCl compliance test to establish your operating limit. Kilns without inline raw mills will not use time weighted compliance test results to make this determination. You must verify an existing operating limit or establish a new operating limit for each kiln, after each repeated performance test. (C) If the average of your three Method 321 compliance test runs (for kilns without an inline raw mill) or the time weighted average of your six Method 321 compliance test runs (for an kiln with an inline raw mill) is below 75 percent of your HCl emission limit, you must calculate an operating limit by establishing a relationship of the average HCl CPMS indicated ppm to the Method 321 test average HCl concentration using the HCl CPMS instrument zero, the average HCl CPMS indicated values corresponding to the three (for kilns without inline raw mills) or time weighted HCl CPMS indicated values corresponding to the six (for kilns with inline raw mills) compliance test runs, and the average HCl concentration (for kilns without raw mills) or average time weighted HCl concentration (for kilns with inline raw mills) from the Method 321 compliance test with the procedures in paragraphs (b)(6)(v)(C)(1) through (5) of this section. (1) Determine your HCl CPMS instrument zero output with one of the following procedures: (i) Zero point data for in situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench. (ii) If neither of the steps in paragraphs (b)(6)(v)(C)(1)(i) through (ii) of this section are possible, you must use a zero output value provided by the manufacturer. (2) If your facility does not have an inline raw mill you will determine your HCl CPMS indicated average in HCl ppm, and the average of your corresponding three HCl compliance test runs, using equation 11a. (3) You will determine your HCl CPMS indicated average in HCl ppm, and the average of your corresponding HCl compliance test runs, using equation 11b. If you have an inline raw mill, use this same equation to calculate a second three-test average for your mill off CPMS and compliance test data. (4) With your instrument zero expressed in ppm, your average HCl CPMS ppm value, and your HCl compliance test average, determine a relationship of performance test HCl (as ppmvd @7% O2) concentration per HCl CPMS indicated ppm with Equation 11c.

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	(5) Determine your source specific 30 kiln operating day operating limit using HC1 CPMS indicated value from Equation 11c in Equation 11d, below. This sets your operating limit at the HC1 CPMS output value corresponding to 75 percent of your emission limit. (D) If the average of your HCl compliance test runs is at or above 75 percent of your HCl emission limit (2.25 ppmvd@7% O2) you must determine your operating limit by averaging the HCl CPMS output corresponding to your HCl performance test runs that demonstrate compliance with the emission limit using Equation 11e. (E) To determine continuous compliance with the operating limit, you must record the HCl CPMS indicated output data for all periods when the process is operating and use all the HCl CPMS data for calculations when the source is not out of control. You must demonstrate continuous compliance with the operating limit by using all quality-assured hourly average data collected by the HCl CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 kiln operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 11f to determine the 30 kiln operating day average. (F) If you exceed the 30 kiln operating day operating limit, you must evaluate the control system operation and re-set the operating limit. (G) The owner or operator of a kiln with an inline raw mill and subject to limitations on HCl emissions must demonstrate initial compliance by conducting separate performance tests while the raw mill is on and while the raw mill is off. Using the fraction of time the raw mill is on calculate your HCl CPMS limit as a weighted average of the HCl CPMS indicated values measured during raw mill on and raw mill off compliance testing using Equation 11g. ~~[(H) Paragraph (b)(6)(v) of this section expires on July 25, 2017 at which time the owner or operator must demonstrate compliance with paragraphs (b)(6)(i), (ii), or (iii).]~~" (amended by **82 Fed. Reg. 28565 (June 23, 2017)** Additionally, §61.1349(b)(6)(v) includes equations and definitions under the following: Eq. 11a Eq. 11b Eq. 11c Eq. 11d Eq. 11e Eq. 11f Eq. 11g §63.1350(l) was revised by adding the following subparagraph "(4) If you monitor continuous performance through the use of an HCl CPMS according to paragraphs (b)(6)(v)(A) through (H) of § 63.1349, for any exceedance of the 30 kiln operating day HCl CPMS average value from the established operating limit, you must: (i) Within 48 hours of the exceedance, visually inspect the APCD; (ii) If inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible and return the HCl CPMS measurement to within the established value; and

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	(iii) Within 30 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct an HCl emissions compliance test to determine compliance with the HCl emissions limit and to verify or reestablish the HCl CPMS operating limit within 45 days. You are not required to conduct additional testing for any exceedances that occur between the time of the original exceedance and the HCl emissions compliance test required under this paragraph. (iv) HCl CPMS exceedances leading to more than four required performance tests in a 12-month process operating period (rolling monthly) constitute a presumptive violation of this subpart." §63.1355(l) was revised by adding the following subparagraph "(e) You must keep records of the daily clinker production rates and kiln feed rates." **81 Fed. Reg. 48359 (July 25, 2016)**
40 CFR 63.1500--63.1520 (Subpart RRR)	No Change
40 CFR 63.1560--63.1579 (Subpart UUU)	63.1563 was revised by amending adding the following paragraphs: "(a)… (1) If you startup your affected source before April 11, 2002, then you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002, except as provided in paragraph (d) of this section. (2) If you startup your affected source after April 11, 2002, you must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of your affected source, except as provided in paragraph (d) of this section. (b) If you have an existing affected source, you must comply with the emission limitations and work practice standards for existing affected sources in this subpart by no later than April 11, 2005 except as specified in paragraph (c) and (d) of this section. (d) You must comply with the applicable requirements in §§ 63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) as specified in paragraphs (d)(1) and (2) of this section, as applicable. (1) For sources which commenced construction or reconstruction before June 30, 2014, you must comply with the applicable requirements in §§ 63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before August 1, 2017 unless an extension is requested and approved in accordance with the provisions in § 63.6(i). After February 1, 2016 and prior to the date of compliance with the provisions in §§ 63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4), you must comply with the requirements in § 63.1570(c) and (d). (2) For sources which commenced construction or reconstruction on or after June 30, 2014, you must comply with the applicable requirements in §§ 63.1564(a)(5), 63.1565(a)(5) and 63.1568(a)(4) on or before February 1, 2016 or upon startup, whichever is later. [~~(d)~~](e) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the requirements in paragraphs [~~(d)~~](e)(1) and (2) of this section apply…

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Changes to 40 CFR 61 and 63 from July 1, 2016, to July 1, 2017

CFR Reference	Summary of Changes to Code of Federal Regulations
	[~~(e)~~](f) You must meet the notification requirements in §63.1574 according to the schedule in §63.1574 and in 40 CFR part 63, subpart A. Some of the notifications must be submitted before the date you are required to comply with the emission limitations and work practice standards in this subpart." 63.1564 was revised by amending the following paragraphs: "(a)… (1) Except as provided in paragraph (a)(5) of this section, meet each emission limitation in Table 1 of this subpart that applies to you. If your catalytic cracking unit is subject to the NSPS for PM in §60.102 of this chapter or is subject to §60.102a(b)(1) of this chapter, you must meet the emission limitations for NSPS units. If your catalytic cracking unit is not subject to the NSPS for PM, you can choose from the [~~four~~] six options in paragraphs (a)(1)(i) through (vi) of this section… (iv) You can elect to comply with the PM per coke burn-off emission limit[~~ in §60.102a(b)(1) of this chapter~~] (Option 2)… (5) [~~During periods of startup, shutdown and hot standby, you can choose from~~] On or before the date specified in §63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown, and hot standby: … (c) (5) If you elect to comply with the alternative limit in paragraph (a)(5)(ii) of this section during periods of startup, shutdown[~~,~~]and hot standby, demonstrate continuous compliance [~~by~~] on or before the date specified in §63.1563(d)…" §63.1565(a)(5) was revised by amending the following text to "[~~During periods of startup, shutdown and hot standby, you can choose from~~] On or before the date specified in § 63.1563(d), you must comply with one of the two options in paragraphs (a)(5)(i) and (ii) of this section during periods of startup, shutdown and hot standby:" §63.1566(a)(4) was revised by amending the following text to "The emission limitations in Tables 15 and 16 of this subpart do not apply to emissions from process vents during passive depressuring when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less or during active depressuring or purging prior to January 30, 2019, when the reactor vent pressure is 5 psig or less. On and after January 30, 2019, [~~T~~]the emission limitations in Tables 15 and 16 of this subpart do apply to emissions from process vents during active purging operations (when nitrogen or other purge gas is actively introduced to the reactor vessel) or active depressuring (using a vacuum pump, ejector system, or similar device) regardless of the reactor vent pressure." §63.1568(a)(4) was revised by amending the following text to "[~~During periods of startup and shutdown~~]On or before the date specified in §63.1563(d), you [~~can choose from~~]must comply with one of the three options in paragraphs (a)(4)(i) through (iii) of this section during periods of startup and shutdown."

R307-214
Changes to 40 CFR 61 and 63 from July 1, 2016, to July 1, 2017

CFR Reference	Summary of Changes to Code of Federal Regulations
	Table 2 to Subpart UUU of Part 63 was amended by revising entry 1. Table 3 to Subpart UUU of Part 63 was amended by revising entry 12. Table 5 to Subpart UUU of Part 63 was amended by revising entry 2. **81 Fed. Reg. 45243 (July 13, 2016)**
63.9980--63.10042 (Subpart UUUUU)	§63.10021(e)(9) extends the reporting date text as follows: "Report the dates of the initial and subsequent tune-ups in hard copy, as specified in §63.10031(f)(5), [~~until April 16, 2017~~] through June 30, 2018. On or [~~A~~]after [~~April 16, 2017~~] July 1, 2018, report the date of all tune-ups electronically, in accordance with §63.10031(f)…" 63.10031was revised by amending the following paragraphs: "(f) On or after [~~April 16, 2017~~] July 1, 2018, within 60 days after the date of completing each performance test, you must submit the performance test reports required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx)... (1) On or after [~~April 16, 2017~~] July 1, 2018, within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in §63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx)... (4) On or after [~~April 16, 2017~~] July 1, 2018, submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under §63.10030(e) to EPA's WebFIRE database by using the CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx)... (6) Prior to [~~April 16, 2017~~] July 1, 2018, all reports subject to electronic submittal in paragraphs (f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool…" **82 Fed. Reg. 16739 (April 6, 2017)**

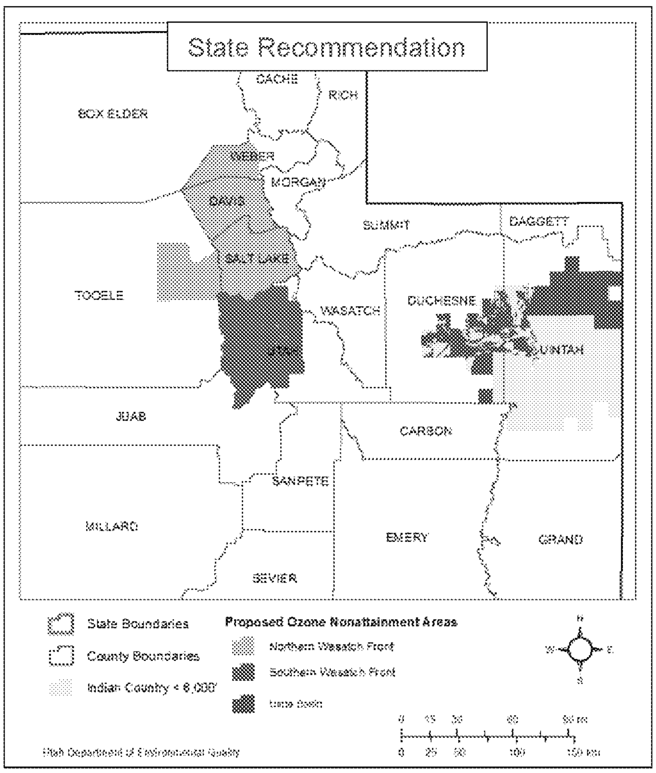
ITEM 8

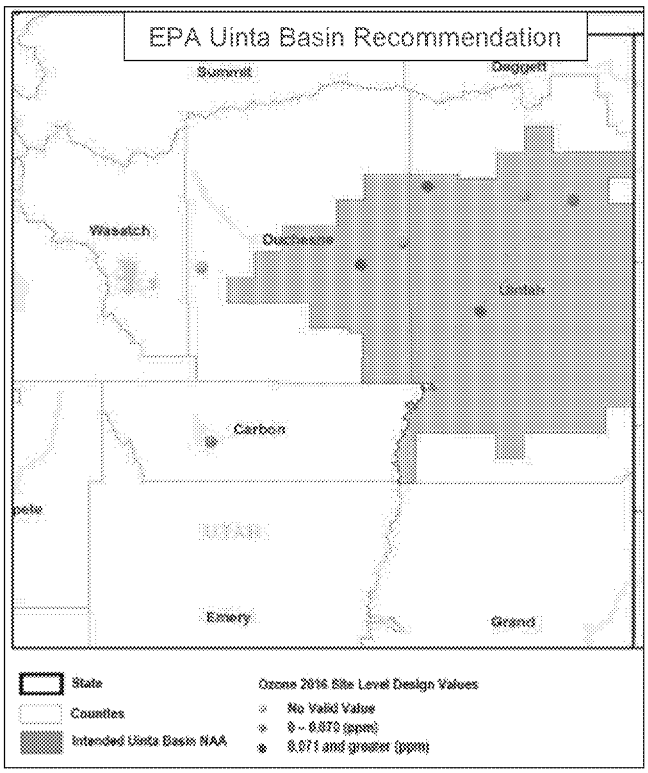
Ozone Designations Update

ENVIRONMENTAL
QUALITY
AIR QUALITY

Ozone Area Designations in Utah

- September 29, 2016 the governor submitted an ozone area designation recommendation to EPA.
- November 6, 2017, EPA agrees with the governor's recommendation for the southern portion of the state by designating certain counties attainment/unclassifiable.
- December 22, 2017, EPA responds to the state recommendation by indicating the anticipated area designations for the remaining portions of Utah.
    - EPA agreed with the recommendation for the Wasatch Front and surrounding counties. See map at bottom left for the state's recommendation.
    - EPA proposes to modify the Uinta Basin recommendation. Utah recommended that Townships with 10% or more of their area at or below 6,000 feet be designated nonattainment. EPA proposes to include Townships with 10% or more of their area at or below 6,250 feet. See the map below at right.
- Area classifications are expected to occur before April. All nonattainment areas in Utah are anticipated to be Marginal.
- A 30-day public comment period will begin when notice of the designations is published in the Federal Register. Utah has until February 28 to respond to EPA's proposed area designations.





If you have questions please contact:
Jay Baker, State Ozone SIP Coordinator – 801.536.4015 | jbaker@utah.gov
Sheila Vance, Uinta Basin Ozone Coordinator – 801.536.4001 | svance@utah.gov

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
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www.epa.gov/region8

DEC 20 2017

Ref: 8P-AR

The Honorable Gary Herbert
Governor of Utah
Utah State Capitol Complex
350 North State Street, Suite 200
P.O. Box 142220
Salt Lake City, Utah 84114-2220

Dear Governor Herbert:

Thank you for your recommendation dated September 29, 2016, on air quality designations for the revised 2015 National Ambient Air Quality Standards (NAAQS) for ozone throughout Utah. I appreciate the information Utah shared with the U.S. Environmental Protection Agency as we move forward to improve ozone air quality. This letter is to notify you of the EPA's preliminary response to Utah's recommendations and to inform you of our approach for completing designations for the revised ozone standards.

On October 1, 2015, the EPA lowered the primary 8-hour ozone standard from 0.075 parts per million (ppm) to 0.070 ppm to provide increased protection of public health. The EPA revised the secondary 8-hour ozone standard, making it identical to the primary standard, to protect against welfare effects, including impacts on sensitive vegetation and forested ecosystems. Working closely with the states and tribes, the EPA is implementing the standards using a common sense approach that improves air quality and minimizes the burden on state and local governments. As part of this routine process, the EPA is working with the states and tribes to identify areas in the country that meet the standards and those that need to take steps to reduce ozone pollution.

As a first step in implementing the 2015 ozone standards, the EPA asked states and tribes to submit in the fall of 2016 their designation recommendations, including appropriate area boundaries. In a first round of designations, published on November 16, 2017, consistent with states' and tribes' recommendations, the EPA designated as Attainment/Unclassifiable most of the country.

As required by the Clean Air Act, the EPA will designate an area as Nonattainment if there are certified, quality-assured air quality monitoring data showing a violation of the 2015 ozone standards or if the EPA makes a determination that the area is contributing to a violation of the standards in a nearby area. Areas designated Attainment/Unclassifiable are not measuring or contributing to a violation of the standards.

After considering Utah's September 29, 2016 ozone designation recommendations, which were based on 2013-2015 air quality data, as well as other relevant technical information (including 2014-2016 air quality data), the EPA intends to designate Salt Lake and Davis Counties as Nonattainment. Additionally, the EPA intends to designate portions of Weber, Tooele, Utah, Uintah, and Duchesne

Counties (including both state and tribal land) as Nonattainment. Finally, the EPA intends to designate all other areas in the state not previously designated in November 2017 as Attainment/Unclassifiable. The enclosed Technical Support Document provides a detailed analysis to support our preliminary decisions for the areas of the state not previously designated. In order for the EPA to consider more current (i.e., 2015-2017) air quality data in the final designation decisions for any area, Utah must submit certified, quality-assured 2015-2017 air quality monitoring data for the area to the EPA by February 28, 2018.

The EPA will continue to work with state officials regarding the appropriate boundaries for the Nonattainment areas in Utah. If Utah has additional information that you would like the EPA to consider, please submit it to us by February 28, 2018. Please submit additional information by sending to the EPA's public docket for these designations, EPA-HQ-OAR-2017-0548, located at www.regulations.gov, and sending a copy to EPA Region 8. The EPA will also make its preliminary designation decisions and supporting documentation available to the general public for review and comment. We will be announcing a 30-day public comment period shortly in the *Federal Register*. After considering additional information we receive, the EPA plans to promulgate final ozone designations in the spring of 2018.

The EPA is committed to working with the states and tribes to reduce ozone air pollution. We look forward to a continued dialogue with you and your staff as we work together to implement the 2015 ozone standards. Should you have any questions regarding this matter, please do not hesitate to contact me or a member of your staff may contact Monica Morales, Region 8's Air Program Director, at (303) 312-6936.

Sincerely,

Douglas H. Benevento
Regional Administrator

Enclosure

Utah:

Northern Wasatch Front, Southern Wasatch Front, and Uinta Basin

Intended Area Designations for the 2015 Ozone National Ambient Air Quality Standards Technical Support Document (TSD)

1.0 Summary

This technical support document (TSD) describes the EPA's intent to designate the Northern Wasatch Front, Southern Wasatch Front, and Uinta Basin in Utah as nonattainment for the 2015 ozone National Ambient Air Quality Standards (NAAQS).

On October 1, 2015, the EPA promulgated revised primary and secondary ozone NAAQS (80 FR 65292; October 26, 2015). The EPA strengthened both standards to a level of 0.070 parts per million (ppm). In accordance with Section 107(d) of the Clean Air Act (CAA), whenever the EPA establishes a new or revised NAAQS, the EPA must promulgate designations for all areas of the country for that NAAQS. The EPA must complete this process within 2 years of promulgating the NAAQS, unless the Administrator has insufficient information to make the initial designations decisions in that time frame. In such circumstances, the EPA may take up to 1 additional year to complete the designations.

Under section 107(d), states were required to submit area designation recommendations to the EPA for the 2015 ozone NAAQS no later than 1 year following promulgation of the standards, i.e., by October 1, 2016.

On September 29, 2016, the State of Utah made designation recommendations for counties in Utah based on air quality data from 2013-2015. The State recommended that Salt Lake and Davis counties, and portions of Weber and Tooele Counties be designated as nonattainment for the 2015 ozone NAAQS. The State also recommended a designation of nonattainment for a portion of Utah County. Additionally, the State of Utah recommended a designation of nonattainment for townships in the counties of Duchesne and Uintah under state air jurisdiction, that are at and below the 6,000-ft elevation.

Tribes were also invited to submit area designation recommendations. On September 27, 2016, the Ute Indian Tribe of the Uintah and Ouray Reservation recommended that the area of tribal land at an unspecified distance around the Ouray ozone monitor in the Uinta Basin be designated as nonattainment for the 2015 ozone NAAQS based on air quality data from 2013-2015. However, the Tribe also recommended that if the EPA concurs on an exceptional event package submitted for two days in June 2015, the Tribe recommends attainment for all tribal land in the Uinta Basin. After considering these recommendations and based on the EPA's technical analysis as described in this TSD, the EPA intends to designate the areas listed in Table 1 as nonattainment for the 2015 ozone NAAQS. The EPA must designate an area nonattainment if it has an air quality monitor that is violating the standard or if it has sources of emissions that are contributing to a violation of the NAAQS in a nearby area. Detailed descriptions of the intended nonattainment boundaries for these areas are found in the supporting technical analysis for each area in Section 3.

Table 1. Utah's Recommended Nonattainment Areas and the EPA's Intended Designated Nonattainment Areas for the 2015 Ozone NAAQS

Area	Utah's Recommended Nonattainment Counties	EPA's Intended Nonattainment Counties
Northern Wasatch Front, Utah	Salt Lake County Davis County Weber County (partial) Tooele County (partial)	Salt Lake County Davis County Weber County (partial) Tooele County (partial)
Southern Wasatch Front, Utah	Utah County (partial)	Utah County (partial)
Uinta Basin*	Duchesne County (partial) Uintah County (partial)	Duchesne County (partial) Uintah County (partial)

*Uinta Basin is a multi-jurisdictional nonattainment area that includes areas of Indian country of Federally-recognized tribes. The areas of Indian country that the EPA intends to designate as part of the nonattainment area are discussed in Section 3.2, Technical Analysis for the Uinta Basin. The Ute Tribe recommended an unspecified nonattainment boundary around the Ouray monitor in Uintah County. The EPA's intended nonattainment area for the Uinta Basin includes both state and tribal land within the specified boundary.

In their letter, Utah recommended that the EPA designate as "attainment" or "unclassifiable/attainment" all other counties and partial counties not identified in the State's Recommended Nonattainment Counties column of Table 1. On November 6, 2017 (82 FR 54232; November 16, 2017), the EPA signed a final rule designating eleven counties (Beaver, Emery, Garfield, Iron, Kane, Millard, Piute, San Juan, Sevier, Washington, and Wayne) in the southern half of the State as attainment/unclassifiable for the 2015 ozone NAAQS. The EPA explains in section 2.0 the approach it is now taking to designate the remaining areas in the State.

The EPA does not intend to modify the State's recommendation for the Northern and Southern Wasatch Front nonattainment areas. However, the EPA does intend to modify the State's recommendations for the Uinta Basin Area.

The EPA also disagrees with Tribe's recommendation, and EPA intends to designate the Tribal area within parts of Uintah County and Duchesne County as nonattainment based on ambient monitoring data collected at Tribal monitors during the 2014-2016 period, where available, showing non-compliance with the 2015 ozone NAAQS. Although the EPA has approved the Tribe's exceptional events demonstration, three monitors included in the demonstration are still showing violations of the 2015 NAAQS, as discussed further in Section 3 – Factor 1.

The EPA will designate all tribes in accordance with two guidance documents issued in December 2011 by the EPA Office of Air Quality Planning and Standards titled, "Guidance to Regions for Working with Tribes during the National Ambient Air Quality Standards (NAAQS)) Designations Process,"[1] and "Policy for Establishing Separate Air Quality Designations for Areas of Indian Country."[2]

2.0 Nonattainment Area Analyses and Intended Boundary Determination

The EPA evaluated and determined the intended boundaries for each nonattainment area on a case-by-case basis, considering the specific facts and circumstances of the area. In accordance with the CAA section 107(d), the EPA intends to designate as nonattainment the areas with monitors that are violating the 2015 ozone NAAQS and nearby areas with emissions sources (i.e., stationary, mobile, and/or area sources) that contribute to the violations. As described in the EPA's designations guidance for the 2015 NAAQS (hereafter referred to as the "ozone designations guidance"),[3] after identifying each monitor indicating a violation of the ozone NAAQS in an area, the EPA analyzed those nearby areas with emissions potentially contributing to the violating area. The EPA believes that using the Core Based Statistical Area (CBSA) or Combined Statistical Area (CSA)[4] as a starting point for the contribution analysis is a reasonable approach to ensure that the nearby areas most likely to contribute to a violating area are evaluated. The area-specific analyses may support nonattainment boundaries that are smaller or larger than the CBSA or CSA. The EPA's analytical approach is described in Section 3 of this technical support document.

On November 6, 2017, the EPA issued attainment/unclassifiable designations for approximately 85% of the United States and one unclassifiable area designation.[5] At that time, consistent with statements in the designations guidance regarding the scope of the area the EPA would analyze in determining nonattainment boundaries, EPA deferred designation for any counties in the larger of a CSA or CBSA where one or more counties in the CSA or CBSA was violating the standard and any counties with a violating monitor not located in a CSA or CBSA. In addition, the EPA deferred designation for any other counties adjacent to a county with a violating monitor. The EPA also deferred designation for any county that had incomplete monitoring data, any county in the larger of the CSA or CBSA where such a county was located, and any county located adjacent to a county with incomplete monitoring data.

The EPA is proceeding to complete the remaining designations consistent with the designations guidance (and EPA's past practice) regarding the scope of the area the EPA would analyze in determining nonattainment boundaries for the ozone NAAQS as outlined above. For those deferred areas where one or more counties violating the ozone NAAQS or with incomplete data are located in a CSA or CBSA, in most cases the technical analysis for the nonattainment area includes any counties in the larger of the relevant

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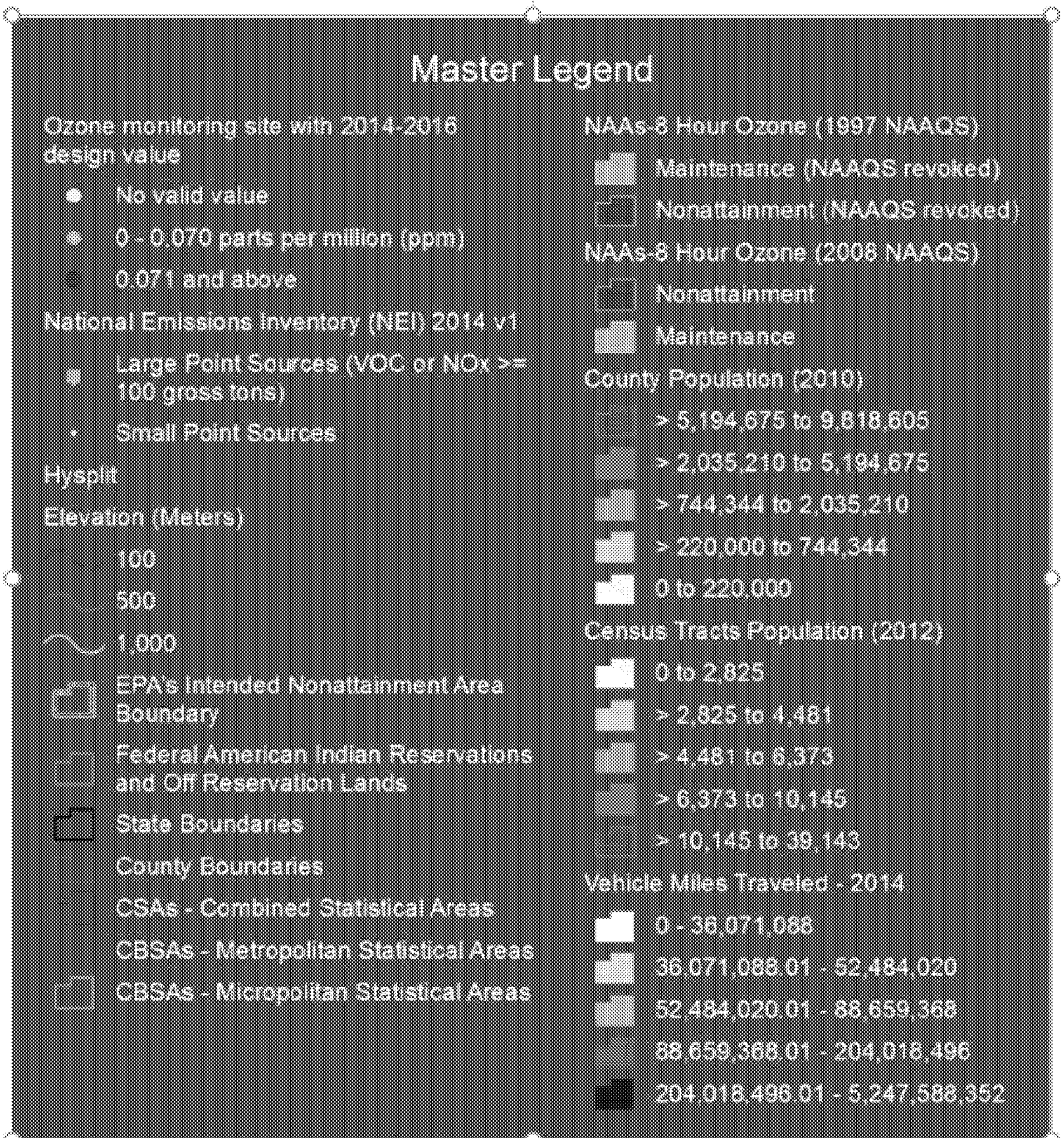
[1] https://www.epa.gov/sites/production/files/2016-02/documents/ozone-designation-tribes.pdf
[2] https://www.epa.gov/sites/production/files/2016-02/documents/indian-country-separate-area.pdf
[3] The EPA issued guidance on February 25, 2016 that identified important factors that the EPA intends to evaluate in determining appropriate area designations and nonattainment boundaries for the 2015 ozone NAAQS. Available at *https://www.epa.gov/ozone-designations/epa-guidance-area-designations-2015-ozone-naaqs*
[4] Lists of CBSAs and CSAs and their geographic components are provided at www.census.gov/population/www/metroareas/metrodef.html. The Office of Management and Budget (OMB) adopts standards for defining statistical areas. The statistical areas are delineated based on U.S. Census Bureau data. The lists are periodically updated by the OMB. The EPA used the most recent July 2015 update (OMB Bulletin No. 15-01), which is based on application of the 2010 OMB standards to the 2010 Census, 2006-2010 American Community Survey, as well as 2013 Population Estimates Program data.
[5] Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards published on November 16, 2017(82 FR 54232).

CSA or CBSA. For counties with a violating monitor not located in a CSA or CBSA, the EPA explains in the 3.0 Technical Analysis section, its decision whether to consider in the five-factor analysis for each area any other adjacent counties for which the EPA previously deferred action. We intend to designate all counties not included in five-factor analyses for a specific nonattainment or unclassifiable area analyses, as attainment/unclassifiable. These deferred areas are identified in a separate document entitled "Intended Designations for Deferred Counties and Partial Counties Not Addressed in the Technical Analyses." which is available in the docket.



Figures in the remainder of this document refer to the master legend above.

3.0 Technical Analyses for Intended Nonattainment Areas

3.1 Technical Analysis for Northern Wasatch Front and Southern Wasatch Front Areas

This technical analysis identifies the areas with monitors that violate the 2015 ozone NAAQS. It also provides EPA's evaluation of these areas and any nearby areas to determine whether those nearby areas have emissions sources that potentially contribute to ambient ozone concentrations at the violating monitors in the area, based on the weight-of-evidence of the five factors recommended in the EPA's ozone designations guidance and any other relevant information. In developing this technical analysis, the EPA used the latest data and information available to the EPA (and to the states and tribes through the Ozone Designations Mapping Tool and the EPA Ozone Designations Guidance and Data web page).[6] In addition, the EPA considered any additional data or information provided to the EPA by states or tribes.

The area of analysis for the Northern Wasatch Front and Southern Wasatch Front areas is the Salt Lake City-Provo-Orem CSA. The CSA is comprised of three Metropolitan Statistical Areas (MSAs) and two Micropolitan Statistical Areas. Because of the size of the counties involved, the Salt Lake City-Provo-Orem CSA is a very large analysis area. It is about the size of the State of West Virginia, and larger than nine other states. The counties that are included in these areas are as follows:

- Ogden-Clearfield MSA: Box Elder County, Davis County, Morgan County, Weber County
- Salt Lake City MSA: Salt Lake County, Tooele County
- Provo-Orem MSA: Juab County, Utah County
- Summit Park Micropolitan Statistical Area: Summit County
- Heber Micropolitan Statistical Area: Wasatch County

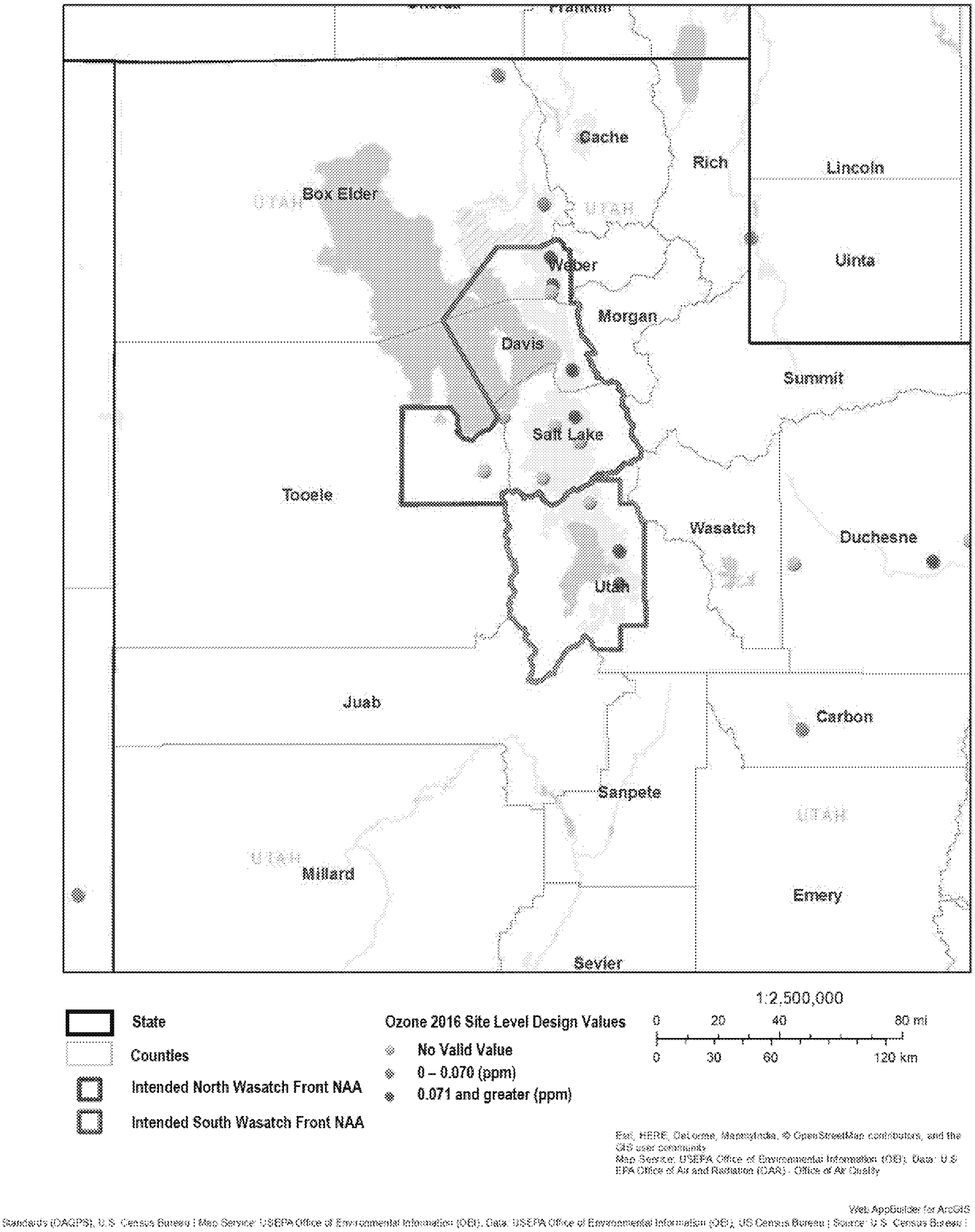
The five factors recommended in the EPA's guidance are:

1. Air Quality Data (including the design value calculated for each Federal Reference Method (FRM) or Federal Equivalent Method (FEM) monitor;
2. Emissions and Emissions-Related Data (including locations of sources, population, amount of emissions, and urban growth patterns);
3. Meteorology (weather/transport patterns);
4. Geography/Topography (including mountain ranges or other physical features that may influence the fate and transport of emissions and ozone concentrations); and
5. Jurisdictional Boundaries (e.g., counties, air districts, existing nonattainment areas, areas of Indian country, Metropolitan Planning Organizations (MPOs)).

Figure 1 is a map of the EPA's intended nonattainment boundaries for the Northern Wasatch Front and Southern Wasatch Front areas. The map shows the location of the ambient air quality monitors, county, and other jurisdictional boundaries.

[6] The EPA's Ozone Designations Guidance and Data web page can be found at *https://www.epa.gov/ozone-designations/ozone-designations-guidance-and-data.*

Figure 1. EPA's Intended Nonattainment Boundaries for the Northern Wasatch Front and Southern Wasatch Front Areas



The State recommended that EPA designate two separate nonattainment areas for counties in this CSA – the Northern Wasatch Front and the Southern Wasatch Front. The EPA is analyzing all of the counties in the

CSA together in this TSD, but, as provided in the conclusion, the EPA does not intend to modify the State's recommendation to designate two separate nonattainment areas.

The EPA must designate as nonattainment any area that violates the NAAQS and any nearby areas that contribute to the violation in the violating area. Davis, Salt Lake, Utah, and Weber Counties have monitors in violation of the 2015 ozone NAAQS, therefore these counties (or portions of these counties) are included in the intended nonattainment areas. Based on the analysis that follows, the EPA determined that portions of Tooele County contribute to violations of the NAAQS in the area. The following sections describe the five factor analysis supporting the intended designations for the Northern and Southern Wasatch Front areas. While the factors are presented individually, they are not independent. The five factor analysis process carefully considers the interconnections among the different factors and the dependence of each factor on one or more of the others, such as the interaction between emissions and meteorology for the area being evaluated.

Factor Assessment

Factor 1: Air Quality Data

The EPA considered 8-hour ozone design values in ppm for air quality monitors in the area of analysis based on data for the 2014-2016 period (i.e., the 2016 design value, or DV). This is the most recent three-year period with fully-certified air quality data. The design value is the 3-year average of the annual 4th highest daily maximum 8-hour average ozone concentration.[7] The 2015 NAAQS are met when the design value is 0.070 ppm or less. Only ozone measurement data collected in accordance with the quality assurance (QA) requirements using approved (FRM/FEM) monitors are used for NAAQS compliance determinations.[8] The EPA uses FRM/FEM measurement data residing in the EPA's Air Quality System (AQS) database to calculate the ozone design values. Individual violations of the 2015 ozone NAAQS that the EPA determines have been caused by an exceptional event that meets the administrative and technical criteria in the Exceptional Events Rule[9] are not included in these calculations. Whenever several monitors are located in a county (or designated nonattainment area), the design value for the county or area is determined by the monitor with the highest valid design value. The presence of one or more violating monitors (i.e. monitors with design values greater than 0.070 ppm) in a county or other geographic area forms the basis for designating that county or area as nonattainment. The remaining four factors are then used as the technical basis for determining the spatial extent of the designated nonattainment area surrounding the violating monitor(s) based on a consideration of what nearby areas are contributing to a violation of the NAAQS.

The EPA identified monitors where the most recent design values violate the NAAQS, and examined historical ozone air quality measurement data (including previous design values) to understand the nature of the ozone ambient air quality problem in the area. Eligible monitors for providing design value data generally include State and Local Air Monitoring Stations (SLAMS) that are operated in accordance with 40

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[7] The specific methodology for calculating the ozone design values, including computational formulas and data completeness requirements, is described in 40 CFR part 50, appendix U.

[8] The QA requirements for ozone monitoring data are specified in 40 CFR part 58, appendix A. The performance test requirements for candidate FEMs are provided in 40 CFR part 53, subpart B.

[9] The EPA finalized the rule on the Treatment of Data Influenced by Exceptional Events (81 FR 68513) and the guidance on the Preparation of Exceptional Events Demonstrations for Wildfire Events in September of 2016. For more information, see *https://www.epa.gov/air-quality-analysis/exceptional-events-rule-and-guidance.*

CFR part 58, appendix A, C, D and E and operating with an FRM or FEM monitor. These requirements must be met in order to be acceptable for comparison to the 2015 ozone NAAQS for designation purposes. All data from Special Purpose Monitors (SPMs) using an FRM or FEM are eligible for comparison to the NAAQS, subject to the requirements given in the March 28, 2016 Revision to Ambient Monitoring Quality Assurance and Other Requirements Rule (81 FR 17248).

The 2014-2016 design values for counties in the area of analysis are shown in Table 2.

Table 2. Air Quality Data (all values in ppm) [a]

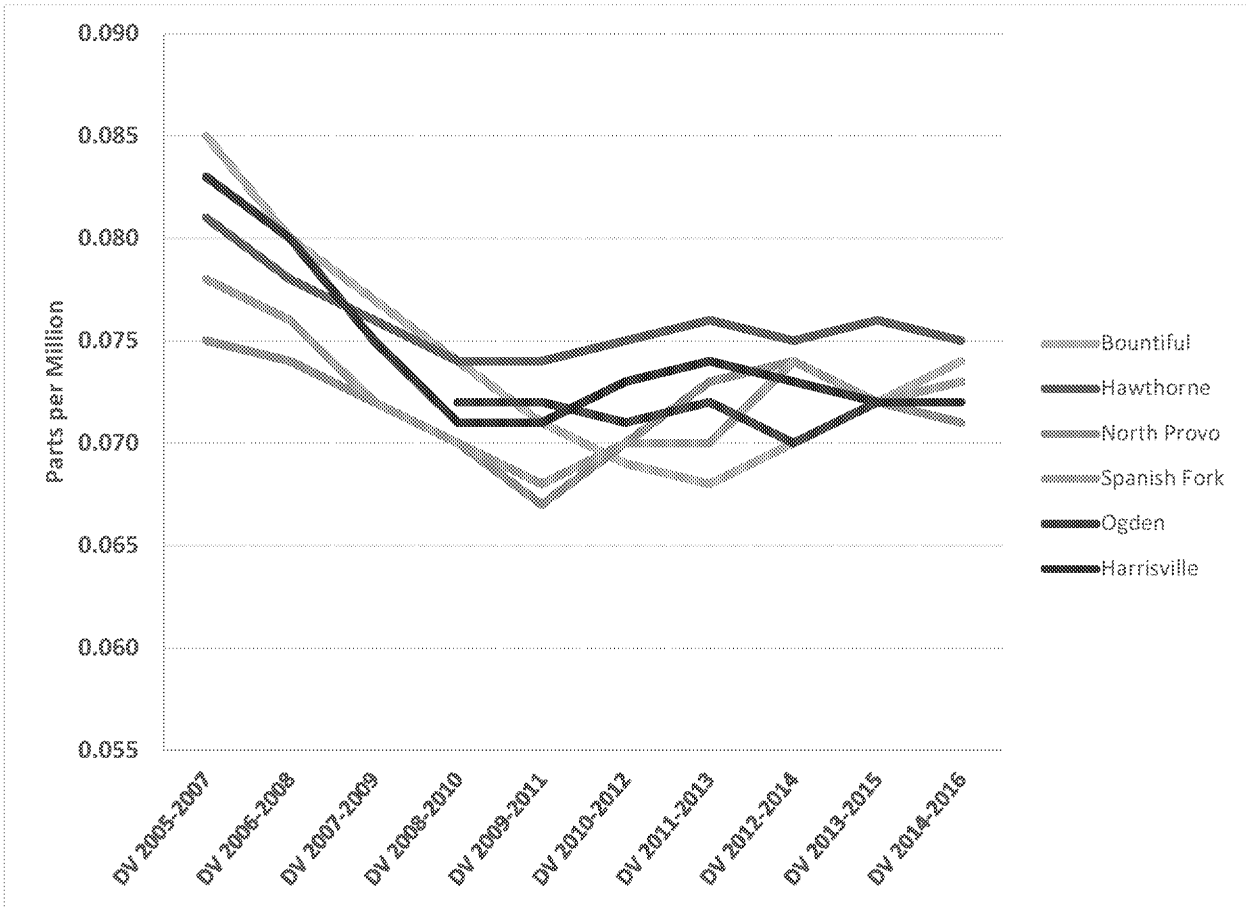
County, State	State Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Box Elder, UT	No	49-003-0003	**0.067**	0.067	0.068	0.067
		49-003-7001	0.059	0.061	0.067	0.051
Davis, UT	Yes	49-011-0004	**0.074**	0.074	0.073	0.076
Juab, UT	No	No monitor	N/A			
Morgan, UT	No	No monitor	N/A			
Salt Lake, UT	Yes	49-035-2004	N/A	0.064	N/A	N/A
		49-035-3006	**0.075**	0.072	0.081	0.074
		49-035-3013	N/A	N/A	0.074	0.076
Summit, UT	No	No monitor	N/A			
Tooele, UT	Yes (partial)	49-045-0003	N/A	0.069	N/A	N/A
		49-045-0004	N/A	N/A	0.071	0.072
Utah, UT	Yes (partial)	49-049-0002	0.071	0.068	0.073	0.072
		49-049-5010	**0.073**	0.076	0.071	0.072
Wasatch, UT	No	No Monitor	N/A			
Weber, UT	Yes (partial)	49-057-0002	0.071	0.070	0.072	0.072
		49-057-1003	**0.072**	0.070	0.074	0.073

The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Davis, Salt Lake, Utah, and Weber Counties show violations of the 2015 ozone NAAQS, therefore these counties are included in the intended nonattainment areas. A county (or partial county) must also be designated nonattainment if it contributes to a violation in a nearby area. Counties adjacent to counties with violating monitors were also evaluated. These include: Tooele, Box Elder, Summit, Juab, Morgan, and Wasatch Counties.

Figure 1, shown previously, identifies the Northern Wasatch Front and Southern Wasatch Front intended nonattainment areas, the county boundaries, and the violating monitors. Table 2 identifies the design values for all monitors in the area of analysis, and Figure 2 shows the historical trend of design values for the violating monitors. As indicated on the map, there are six violating monitors that are located in the area of analysis. Four are located in the Northern Wasatch Front area (Bountiful, located at Viewmont High School in Davis County; Hawthorne, at Hawthorne Elementary School in Salt Lake City, Ogden in Weber County; and Harrisville at Majestic Elementary School, north of Ogden, also in Weber County) and two are located in the Southern Wasatch Front area (North Provo and Spanish Fork at the Spanish Fork-Springville Airport in Utah County). Additional monitors in the Salt Lake City-Provo-Orem CSA not violating the 2015 ozone NAAQS are in Brigham City, in Box Elder County, and the monitor of the Northwest Band of Shoshone Indian Tribe in Washakie Junction, also in Box Elder County.

Figure 2. Three-Year Design Values for Violating Monitors.



Based on Figure 2, ozone monitors in Salt Lake and Weber Counties have consistently had design values above the level of the 2015 ozone NAAQS. Monitors in Utah and Davis Counties historically were above the level of 2015 standard, then dropped below the standard based on the 2011 to 2013 DVs, but more recently have recorded new violations.

Factor 2: Emissions and Emissions-Related Data

The EPA evaluated ozone precursor emissions of nitrogen oxides (NO_x) and volatile organic compounds (VOC) and other emissions-related data that provide information on areas contributing to violating monitors.

Emissions Data

The EPA reviewed data from the 2014 National Emissions Inventory (NEI). For each county in the area of analysis, the EPA examined the magnitude of large sources (NO_x or VOC emissions greater than 100 tons per year) and small point sources and the magnitude of county-level emissions reported in the NEI. These county-level emissions represent the sum of emissions from the following general source categories: point sources, non-point (i.e., area) sources, non-road mobile, on-road mobile, and fires. Emission levels from sources in a nearby area indicate the potential for the area to contribute to monitored violations.

Table 3 provides a county-level emissions summary of NO_x and VOC (given in tons per year (tpy)) emissions for counties in the area of analysis.

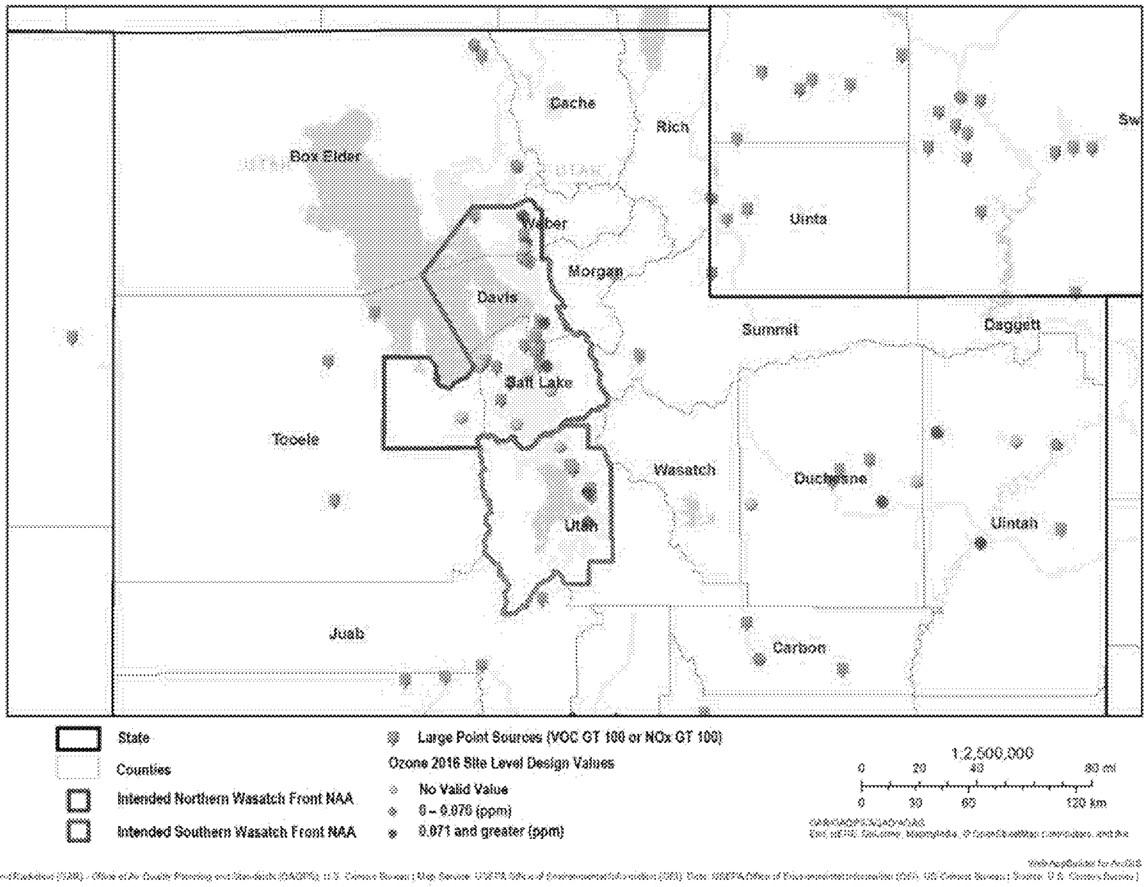
Table 3. Total County-Level NOx and VOC Emissions.

County	State Recommended Nonattainment	Total NO_x (tpy)	Total VOC (tpy)
Salt Lake	Yes	27,011	21,084
Utah	Yes (partial)*	13,208	10,219
Davis	Yes	6,623	6,801
Tooele	Yes (partial)*	5,022	3,484
Box Elder	No	4,579	4,635
Weber	Yes (partial)*	4,948	4,770
Summit	No	3,937	2,346
Juab	No	1,973	1,726
Morgan	No	2,181	1,387
Wasatch	No	1,143	1,737
	Area Wide:	70,625	58,189

* For state recommended partial counties, the emissions shown are for the entire county.

In addition to reviewing county-wide emissions of NO_x and VOC in the area of analysis, the EPA also reviewed emissions from large point sources. The location of these sources, together with the other factors, can help inform nonattainment boundaries. The locations of the large point sources are shown in Figure 3 below. The intended nonattainment boundaries are also shown.

Figure 3. Large Point Sources in the Area of Analysis



As shown in Table 3, Salt Lake County has the highest emissions of both VOC and NOx – more than double the emissions of Utah County, which has the next highest emissions. Davis County has approximately one quarter the level of emissions of Salt Lake County. Toole, Box Elder and Summit Counties have emissions that are somewhat lower than those of Davis County while Juab, Morgan and Wasatch Counties have the lowest level of emissions of the counties in the area of analysis.

Figure 3 shows that there is a heavy concentration of large point sources in Salt Lake County. Utah, Davis and Weber Counties also have several large point sources. Toole County, which is a geographically large county on the western edge of the area of analysis has three large point sources that are somewhat distant from the core metropolitan area.

Population density and degree of urbanization

In this part of the factor analysis, the EPA evaluated the population and vehicle use characteristics and trends of the area as indicators of the probable location and magnitude of non-point source emissions. These include emissions of NO_x and VOC from on-road and non-road vehicles and engines, consumer products, residential fuel combustion, and consumer services. Areas of dense population or commercial development are an indicator of area source and mobile source NO_x and VOC emissions that may contribute to violations of the NAAQS. Table 4 shows the population, population density, and population growth information for each county in the area of analysis. Figure 4 shows the county-level population for the area of analysis, and Figure 5 shows the population density by census tract for the area of analysis.

Table 4. Population and Growth

County Name	State Recommended Nonattainment?	2010 Population	2015 Population	2015 Populations Density (per sq. mi.)	Absolute Change in Population (2010-2015)	Population % Change (2010-2015)
Salt Lake County	Yes	1,029,655	1,107,314	1,492	77,659	8
Utah County	Yes (partial)*	516,564	575,205	287	58,641	11
Davis County	Yes	306,479	336,043	1,125	29,564	10
Weber County	Yes (partial)*	231,236	243,645	423	12,409	5
Tooele County	Yes (partial)*	58,218	62,952	9	4,734	8
Box Elder County	No	49,975	52,097	9	2,122	4
Summit County	No	36,324	39,633	21	3,309	9
Wasatch County	No	23,530	29,161	25	5,631	24
Morgan County	No	9,469	11,065	18	1,596	17
Juab County	No	10,246	10,594	3	348	3
* For state recommended partial counties, the data are for the entire county.						

Source: U.S. Census Bureau population estimates for 2010 and 2015. www.census.gov/data.html.

Figure 4. County-Level Population

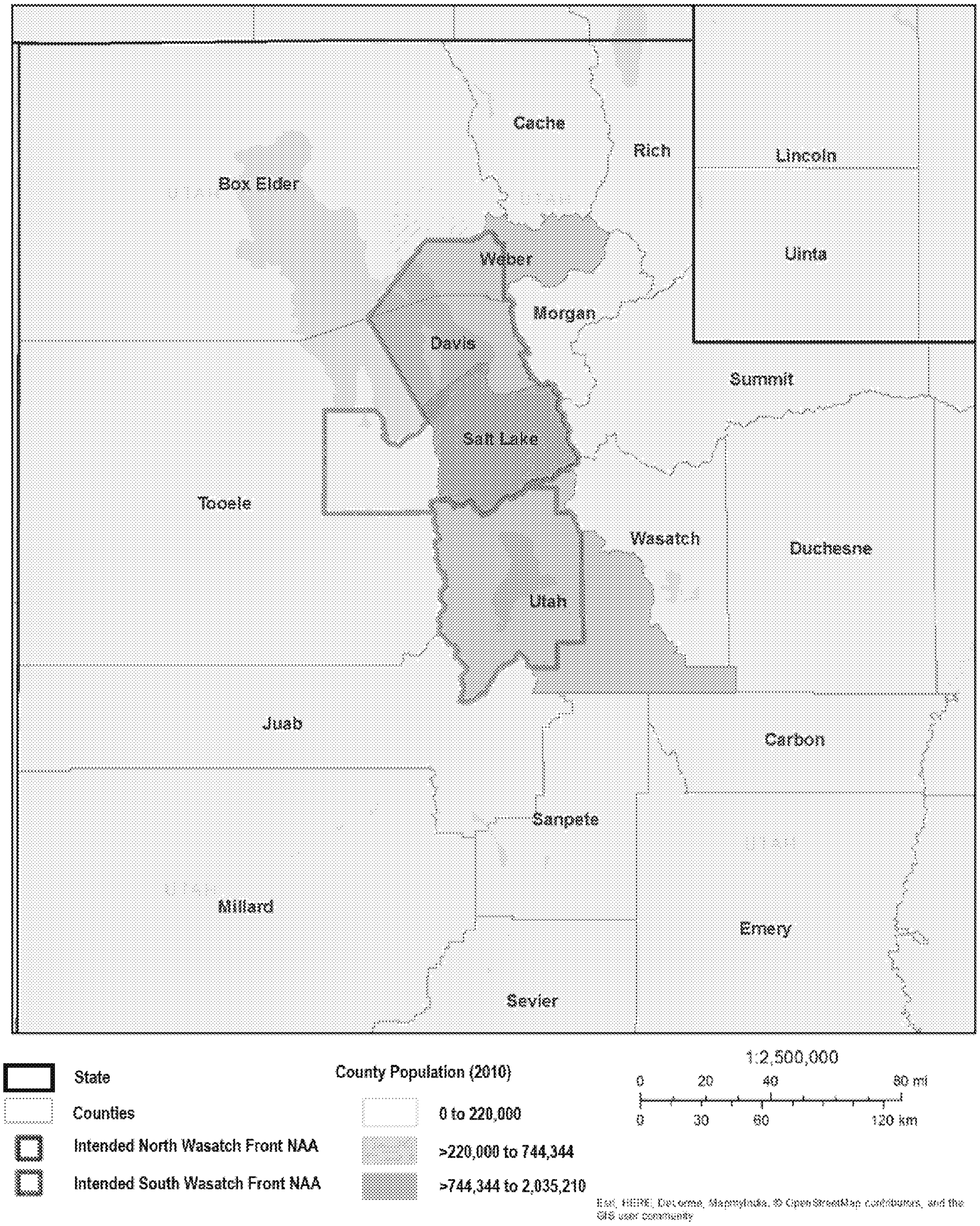


Figure 5. Population Density by Census Tract (2010)

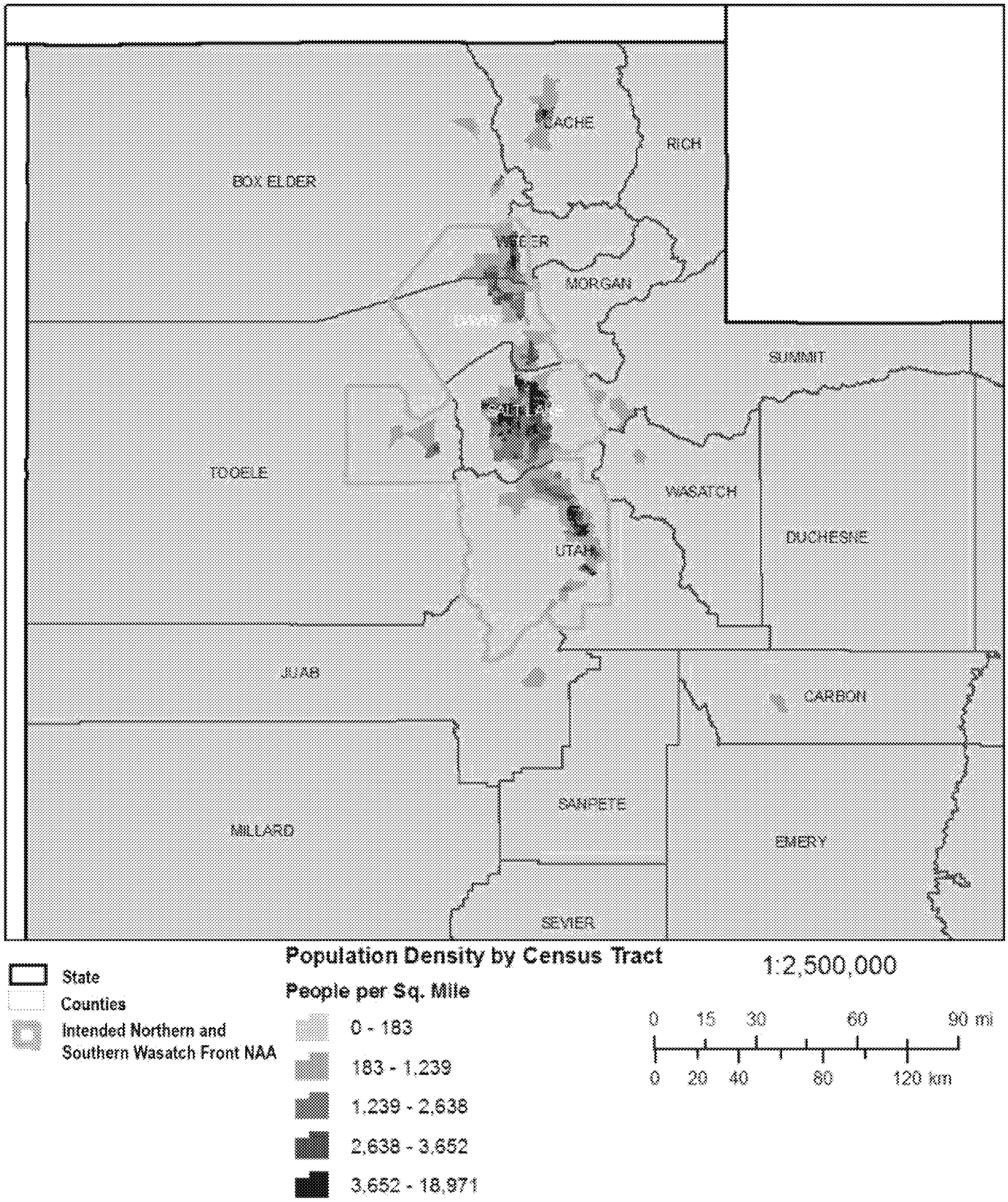


Table 4, along with Figures 4 and 5, show that the majority of the population resides in Salt Lake, Utah, Davis, and Weber Counties. Salt Lake County has a significantly higher population than the other counties – almost twice the population of Utah County, three times that of Davis County and more than four times that of Weber County. The other five counties all have much less than 10 percent of the population of Salt Lake County. Salt Lake and Davis County have the highest population densities of 1492 and 1,125, respectively.

This is more than two to three times that of Weber County and four to five times that of Utah County. The remaining counties have significantly lower population densities of less than 25 people per square mile. As a region, the area is experiencing significant population growth, ranging from 3 to 24 percent. The two counties with the highest percentage population change are two of the least populated counties – Wasatch and Morgan. Of the four counties with the highest population and highest population density, Utah and Davis County had at or just above 10 percent growth, while Salt Lake County had 8 percent growth and Weber has 5 percent growth. As shown by Figure 5, the portions of Utah, Weber, and Tooele Counties that the State has excluded from its nonattainment area recommendation are the least populated and least densely populated areas of those counties.

The State's analysis in their TSD provided with their boundary recommendation provides an examination of population density and urbanization and is included in italicized text below.

> *There are two very noticeable features of the CSA. The first feature is the small area that is urbanized compared to the rural and uninhabited portions of the counties. The second feature is the large size of the CSA. The Salt Lake City-Provo-Orem CSA contains ten counties and covers 25,365 square miles (larger than West Virginia and nine other US states). It extends east/west from the Nevada border to the southern Wyoming border, a distance of over 220 miles, and south from the Idaho border approximately 100 miles. Each of the MSAs within the CSA includes densely populated areas, sparsely populated areas, and very large areas with no population at all. The sparse or unpopulated areas are due to extended desert in the west and extreme mountainous terrain in the east. The largest concentration of both population and industry is found in the low valleys west of, and adjacent to, the Wasatch Front. Smaller concentrations of population are also found in some of the higher valleys east of the Wasatch Range, but there are generally few or no major industrial sources located in these areas.*

Traffic and Vehicle Miles Travelled (VMT)

The EPA evaluated the commuting patterns of residents, as well as the total vehicle miles traveled (VMT) for each county in the area of analysis. In combination with the population/population density data and the location of main transportation arteries, this information helps identify the probable location of non-point source emissions. A county with high VMT and/or a high number of commuters is generally an integral part of an urban area and high VMT and/or high number of commuters indicates the presence of motor vehicle emissions that may contribute to violations of the NAAQS. Rapid population or VMT growth in a county on the urban perimeter may signify increasing integration with the core urban area, and thus could indicate that the associated area source and mobile source emissions may be appropriate to include in the nonattainment area. In addition to VMT, the EPA evaluated worker data collected by the U.S. Census Bureau[10] for the counties in the area of analysis. Table 5 shows the traffic and commuting pattern data, including total VMT for each county in the area of analysis, number of residents who work in each county, number of residents that work in counties with violating monitors, and the percent of residents working in counties with violating monitors. The values in Table 5 are 2014 data.

[10] The worker data can be accessed at: http://onthemap.ces.census.gov/.

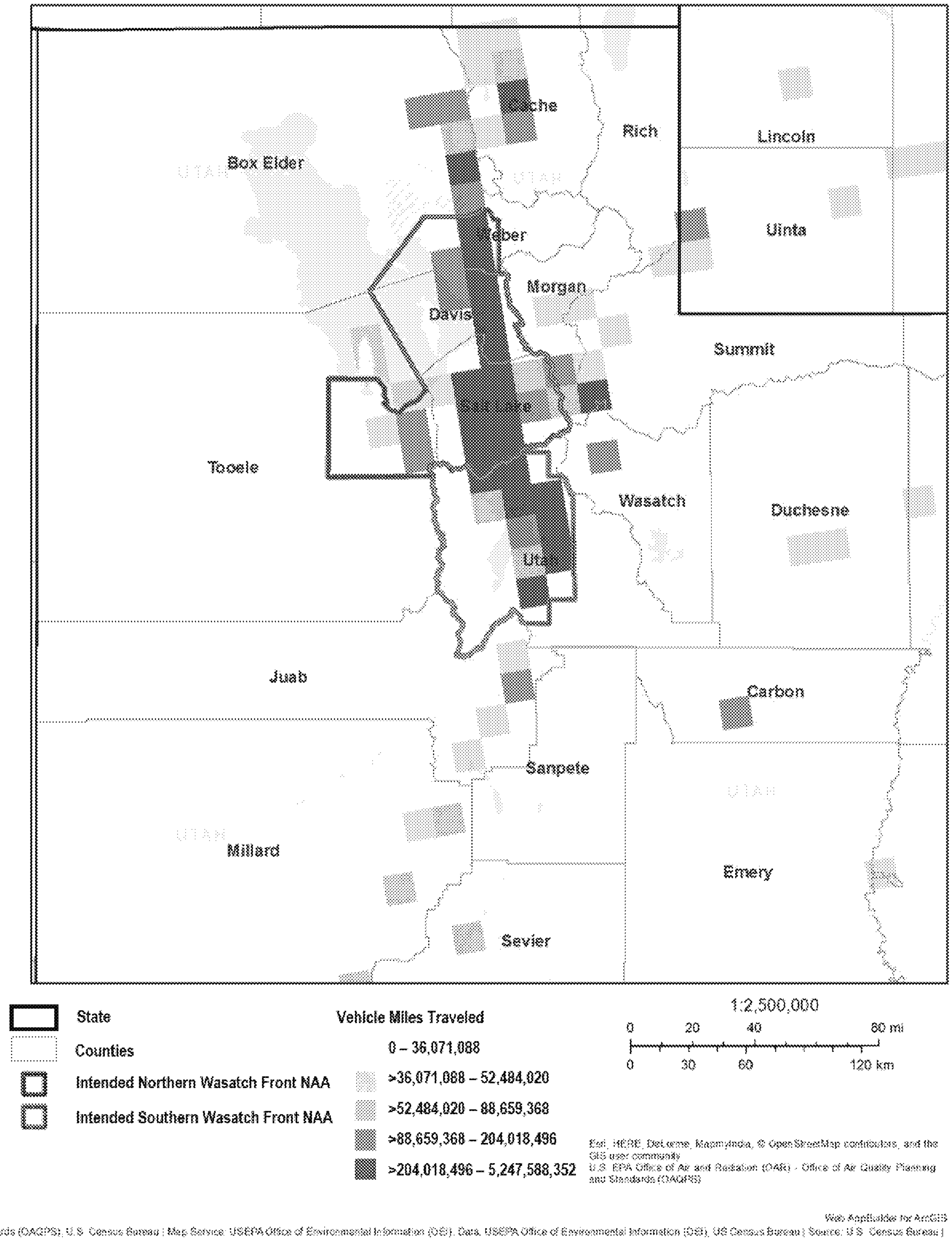
Table 5. Traffic and Commuting Patterns

County	State Recommended Nonattainment?	2014 Total VMT (Million Miles)	Number of County Residents Who Work	Number Commuting to or Within Counties with Violating Monitor(s)	Percentage Commuting to or Within Counties with Violating Monitor(s)
Salt Lake	Yes	9,079	505,823	483,032	95.5%
Utah	Yes (partial)*	4,085	218,761	204,465	93.5%
Davis	Yes	2,590	132,850	125,975	94.8%
Weber	Yes (partial)*	1,647	102,326	94,822	92.7%
Box Elder	No	911	24,932	11,335	45.5%
Tooele	Yes (partial)*	822	26,570	17,098	64.4%
Summit	No	763	21,640	9,345	43.2%
Juab	No	369	4,346	1,795	41.3%
Wasatch	No	353	12,577	5,502	43.8%
Morgan	No	133	4,671	3,134	67.1%
Total		20,752	1,054,496	956,503	90.7%

* For state recommended partial counties, the data provided are for the entire county. Counties with a monitors violating the NAAQS are indicated in bold.

To show traffic and commuting patterns, Figure 6 overlays twelve-kilometer gridded VMT from the 2014 NEI with a map of the transportation arteries.

Figure 6. Twelve Kilometer Gridded VMT (Miles) Overlaid with Transportation Arteries



The 2014 VMT in Table 5 illustrates that the vast majority of vehicle trips occur in four counties. Weber, Davis, Salt Lake, and Utah Counties; which have VMT levels ranging from just over 1600 in Weber County to just over 9000 in Salt Lake County. Figure 6 illustrates that traffic patterns are heaviest on a north-south axis through the area of analysis. This corresponds with the major traffic corridor of Interstate 15. In addition, the heavier traffic areas shown in Figure 6 largely correspond with the more densely populated areas as shown in Figure 5, above – including the counties of Weber, Davis, Salt Lake, and Utah. Average daily traffic rapidly diminishes beyond this central core as indicated by the lower VMT values for the other five counties in the area of analysis and by Figure 6. The commuting information indicates that the number of commuters traveling to or within a county with a violating monitor is more than twice as high for the four counties with violating monitors (each over 90%) than for the other counties - with the exception of Tooele and Morgan Counties. These two counties have approximately 65% of commuters traveling to a county with a violating monitor. As noted previously, Tooele County is relatively sparsely populated except for a small area close to the border of Salt Lake County.

Factor 3: Meteorology

Evaluation of meteorological data helps to assess the fate and transport of emissions contributing to ozone concentrations and to identify areas potentially contributing to the monitored violations. Results of meteorological data analysis may inform the determination of nonattainment area boundaries. In order to determine how meteorological conditions, including, but not limited to, weather, transport patterns, and stagnation conditions, could affect the fate and transport of ozone and precursor emissions from sources in the area, the EPA evaluated 2014-2016 HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory) trajectories at 100, 500, and 1000 meters above ground level (AGL) that illustrate the three-dimensional paths traveled by air parcels to a violating monitor. Figures 7 through 12 show the 24-hour HYSPLIT back trajectories for each exceedance day (i.e., daily maximum 8 hour values that exceed the 2015 ozone NAAQS) for the violating monitors.

Figure 7. HYSPLIT Back Trajectories for Hawthorne

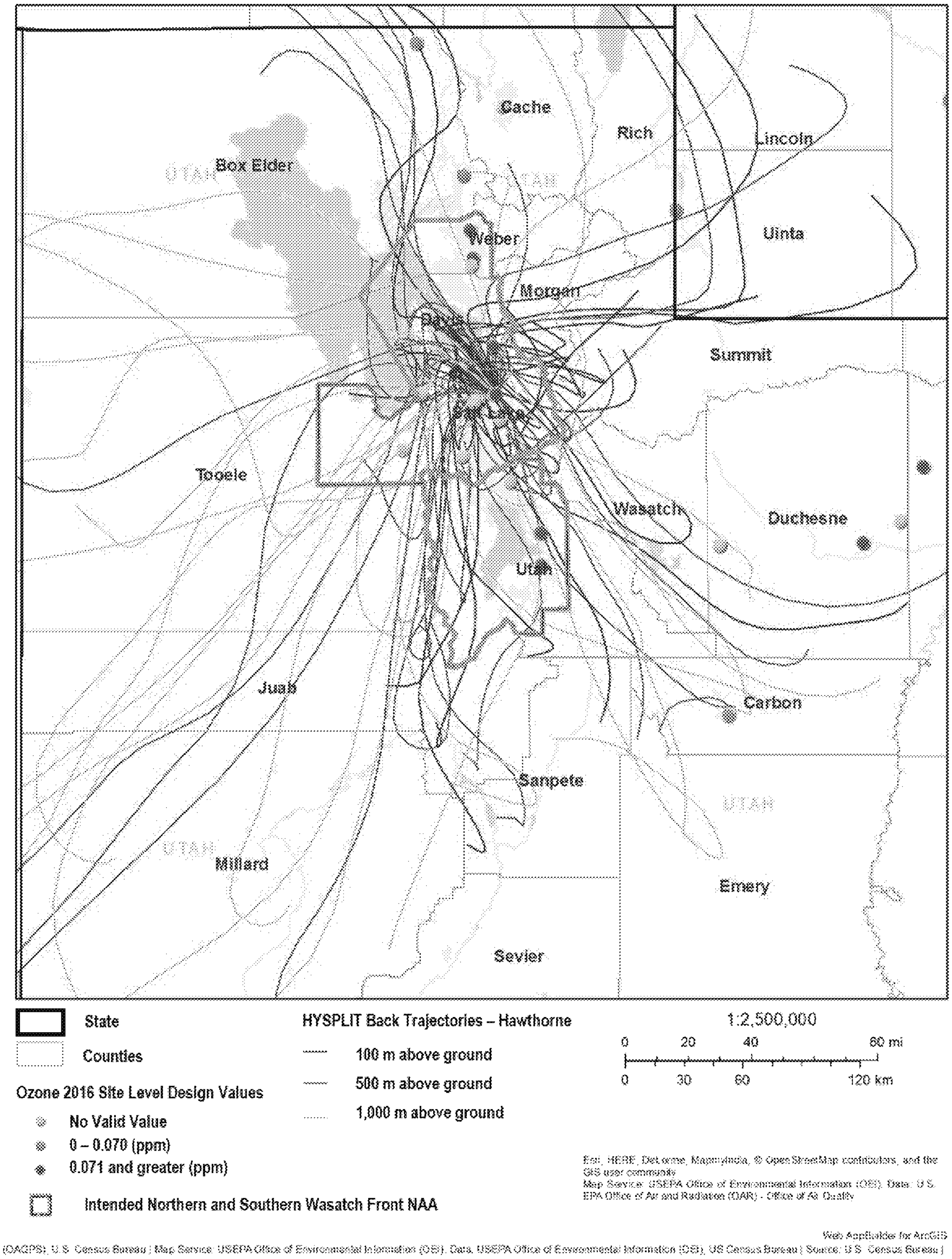


Figure 8. HYSPLIT Back Trajectories for Ogden

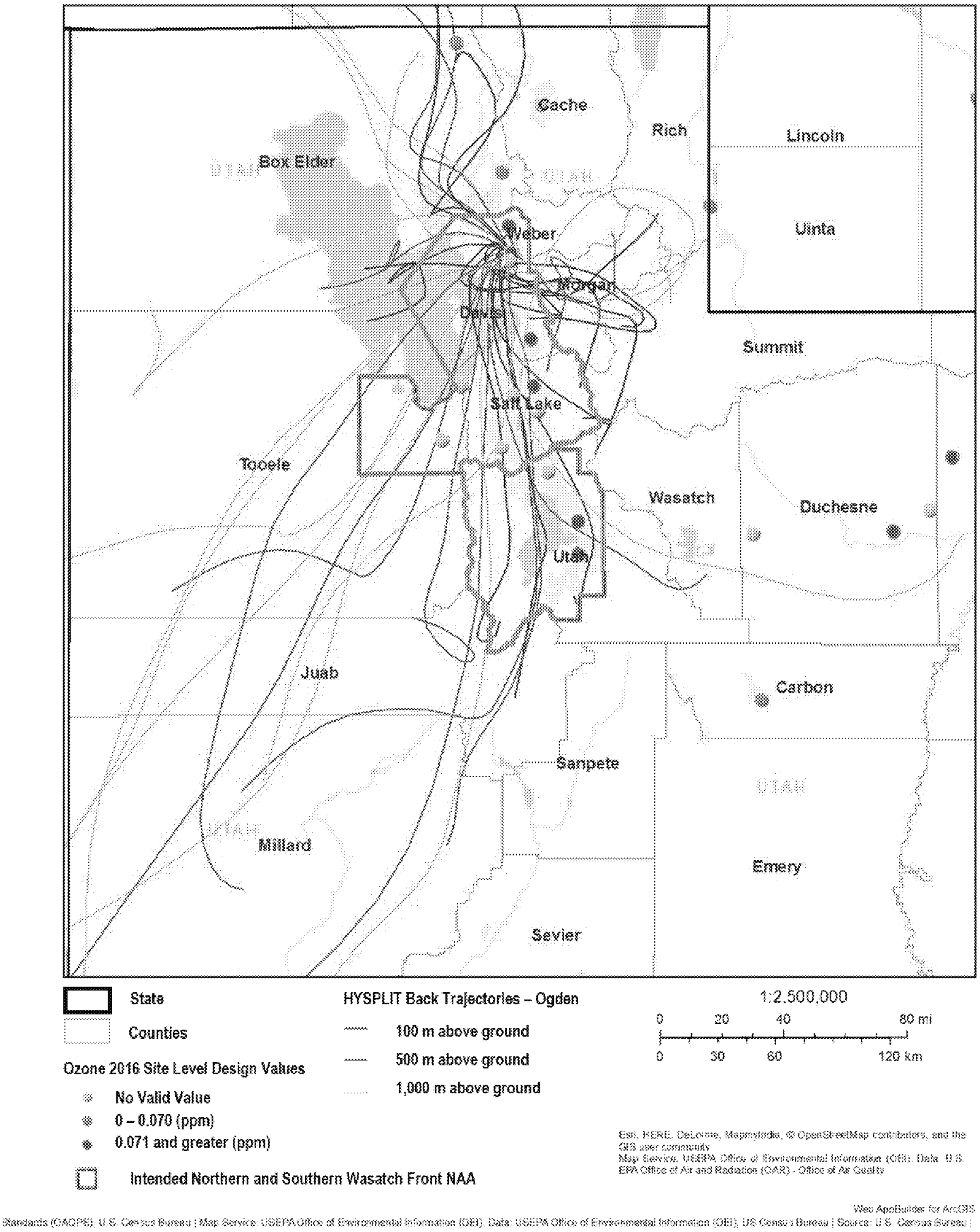


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Figure 9. HYSPLIT Back Trajectories for Bountiful

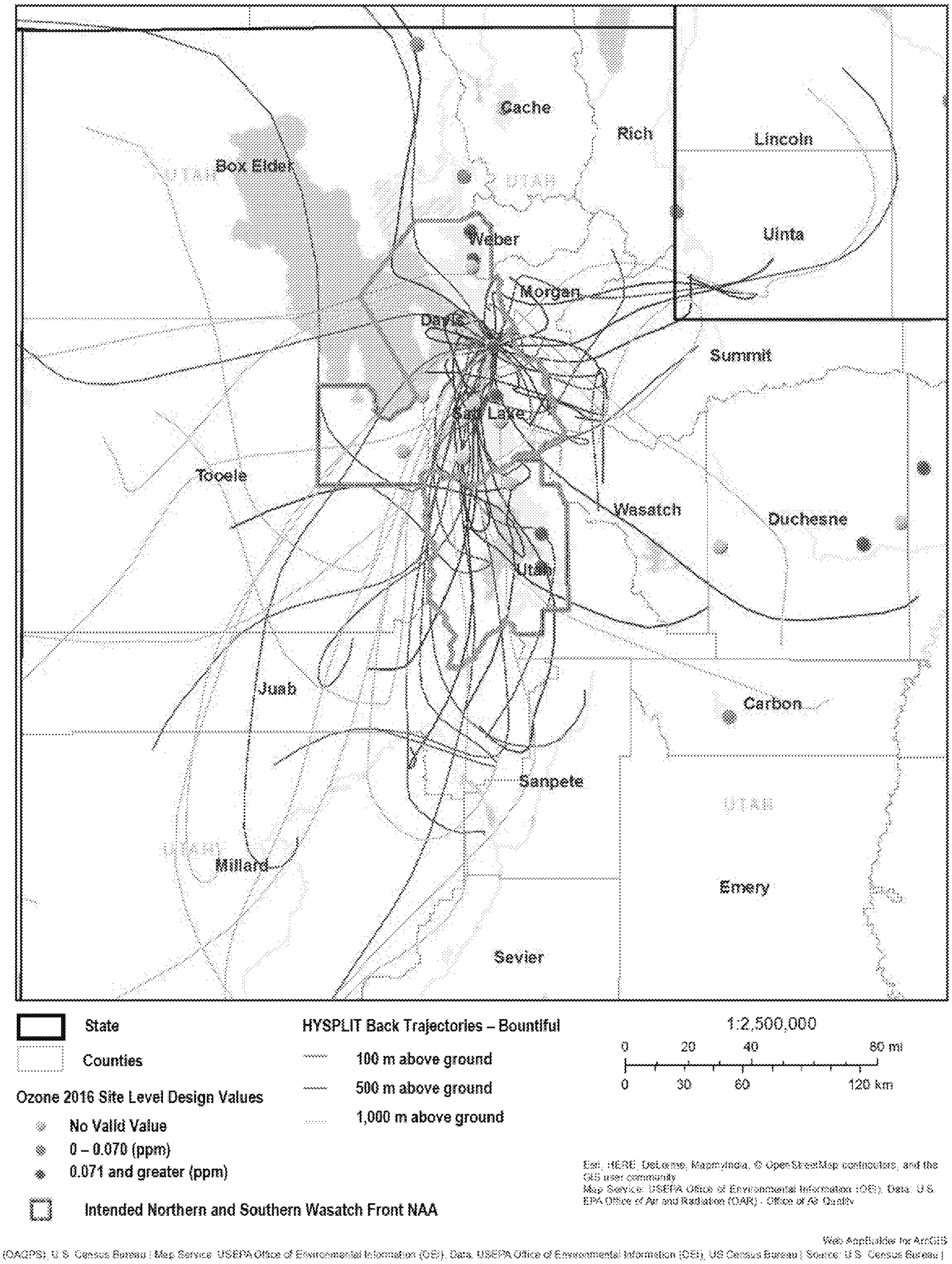


Figure 10. HYSPLIT Back Trajectories for Harrisville

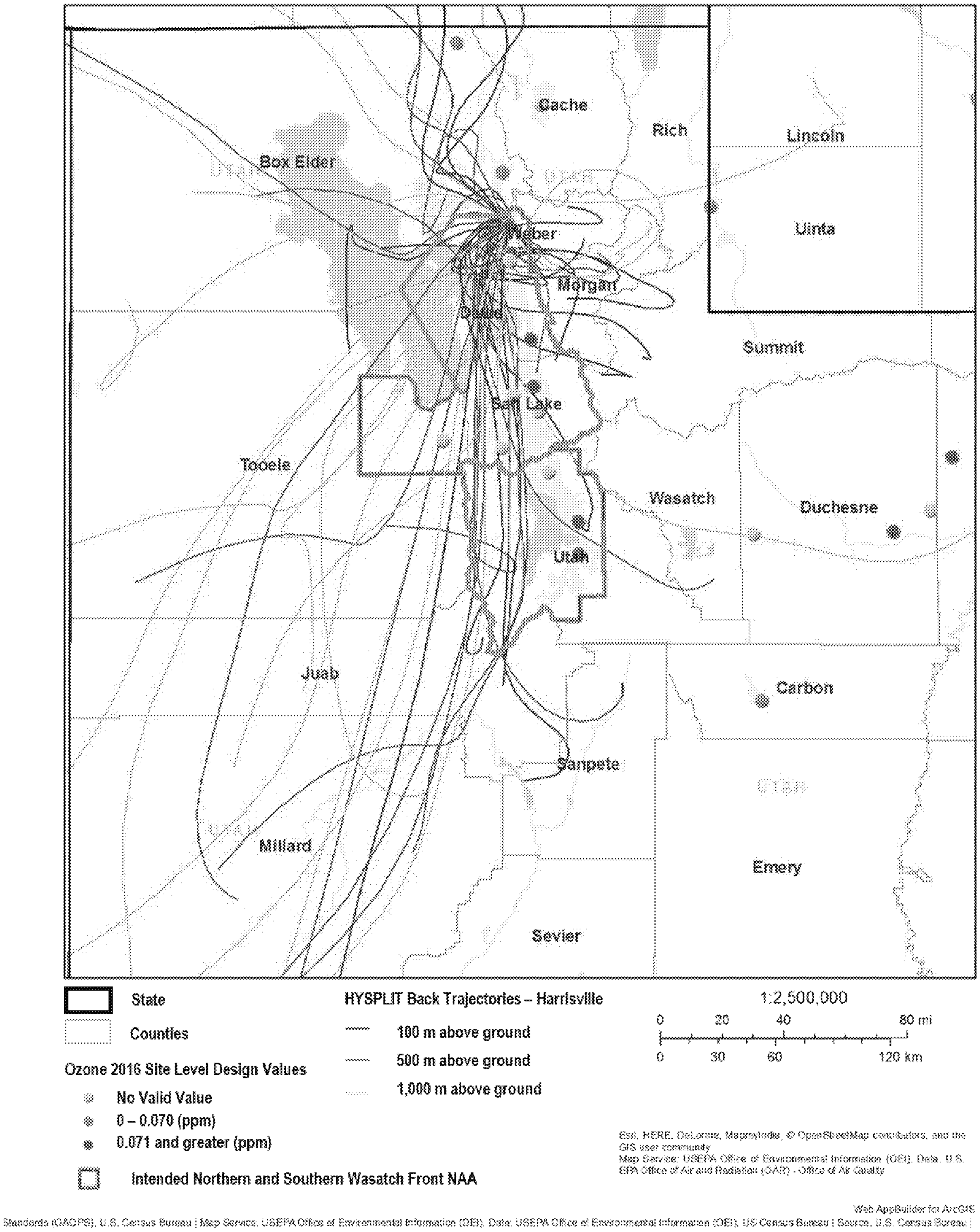


Figure 11. HYSPLIT Back Trajectories for North Provo

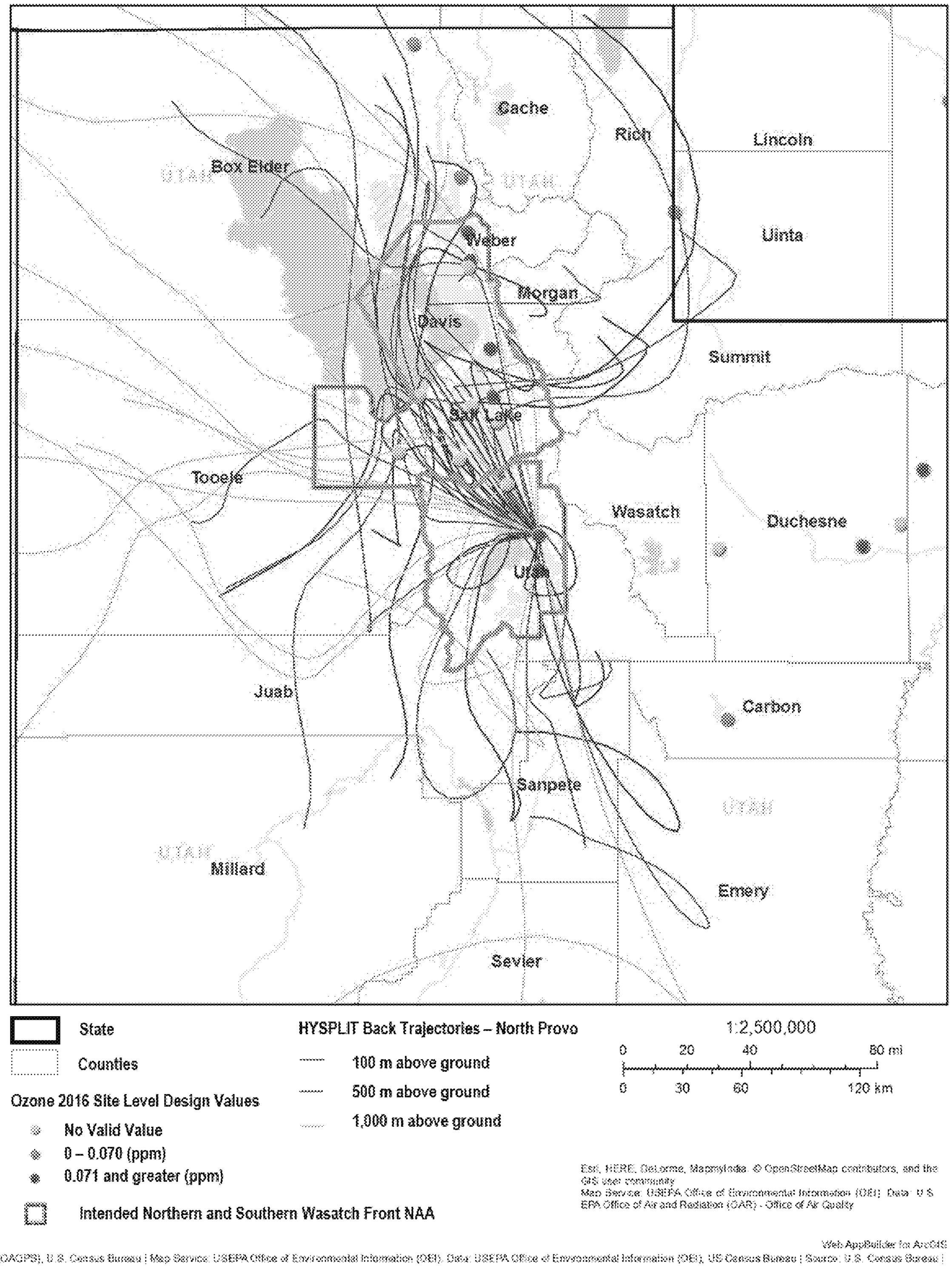
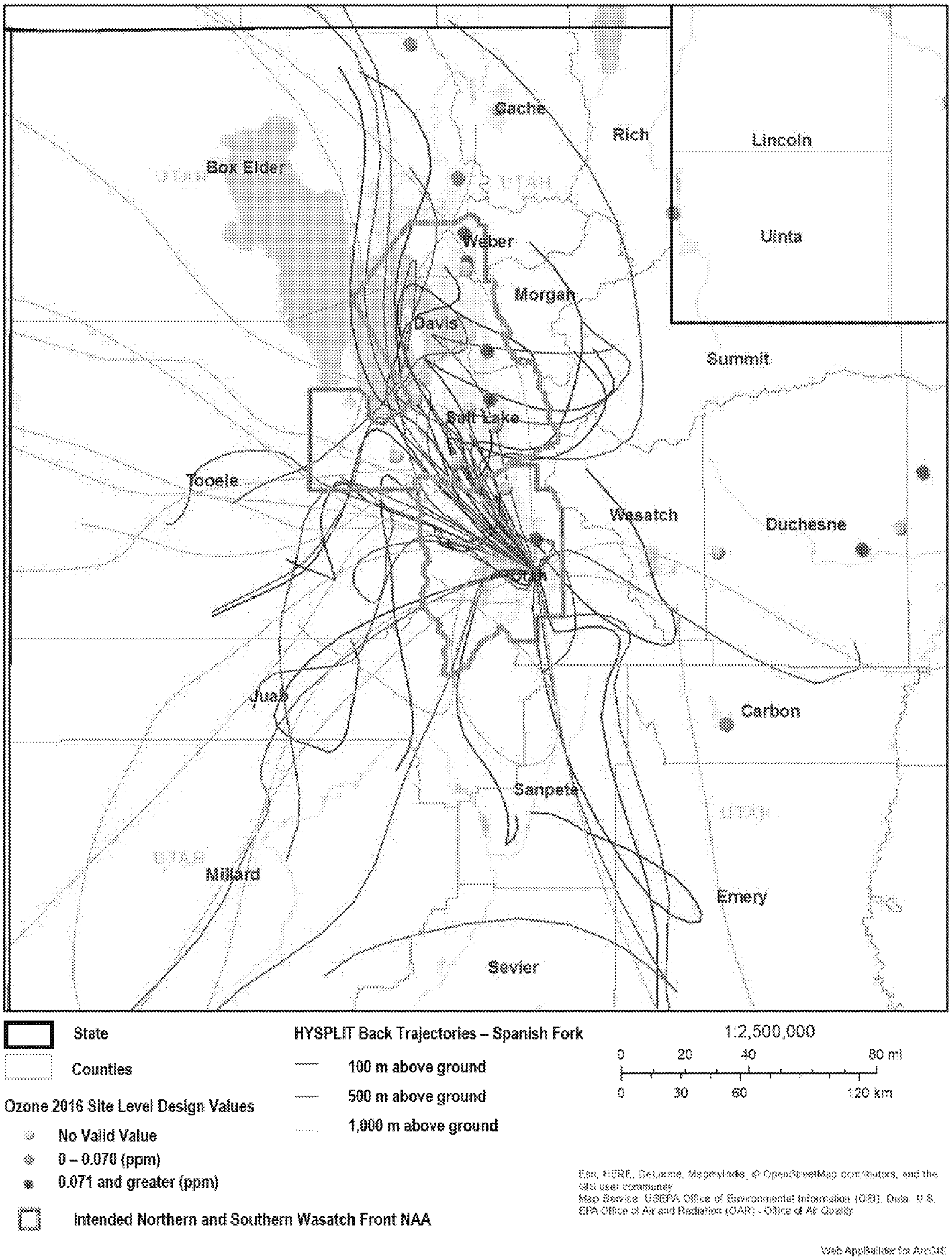


Figure 12. HYSPLIT Back Trajectories for Spanish Fork



The meteorology of the urbanized Wasatch Front is strongly influenced by the Wasatch mountain range to the east of the urban corridor and the Great Salt Lake and Utah Lake, generally to the west of the urbanized area. High ozone levels in the Wasatch front area usually occur in association with a semi-permanent high pressure ridge stationary over the intermountain region, along with clear skies, intense direct sunlight, and stagnant air with very light surface winds. When these meteorological conditions occur together, they aid in the formation of ozone while at the same time providing minimal vertical mixing.

Day-to-day transport of the ozone along the Wasatch Front is mainly influenced by the diurnal effects of the local lake on-shore/off-shore flow coupled with up-slope/down-slope airflow in the mountains. General westward movement occurs during the late evening and nighttime hours and eastward movement occurs during the daylight hours. This is a typical mountain/valley flow.

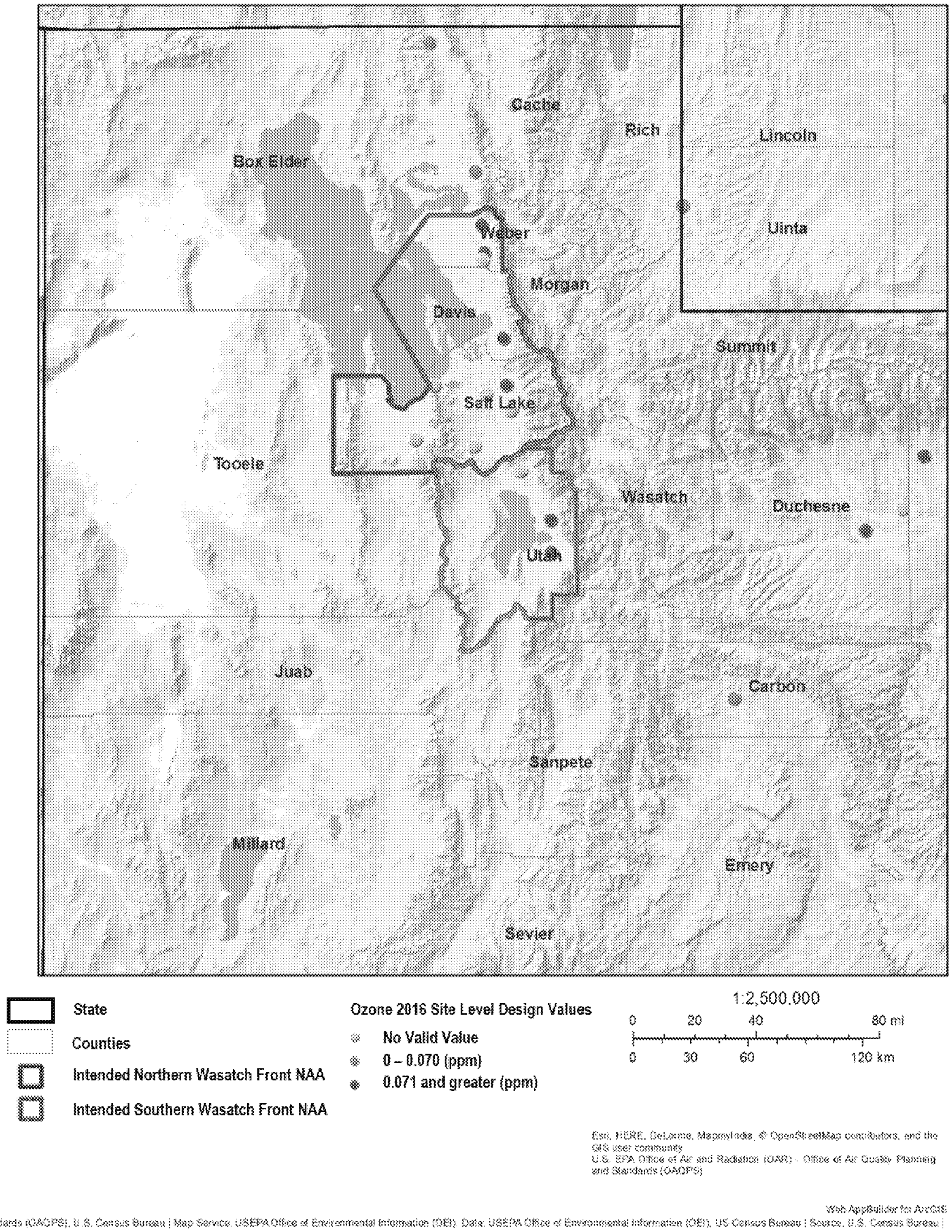
The above meteorological conditions, when combined with topography and other factors, help to define the airsheds of the northern and southern Wasatch Front areas. The back trajectory analysis done with HYSPLIT (Figures 7 through 12) indicates that emissions originating within Davis and Salt Lake Counties as well as the southern portion of Weber County, the northern portion of Utah County, and the eastern portion of Tooele County, appear to be the primary influencer on violating monitors. The EPA notes that a high frequency of days show parcels of air passing through the urbanized eastern portion of Tooele County that influence violating monitors. Additionally, very few days show parcels of air originating in both western Tooele County and Box Elder County that influence violating monitors. In general, the HYSPLIT analysis shows wind patterns predominantly from the south and from the north with the heaviest concentration of trajectories traveling through Salt Lake, Weber, Davis, and Utah Counties. This is consistent with the meteorological pattern discussed earlier, given that some local topographical influence on meteorology occurs on scales smaller than the HYSPLIT gridded meteorology.

Factor 4: Geography/topography

Consideration of geography or topography can provide additional information relevant to defining nonattainment area boundaries. Analyses should examine the physical features of the land that might define the airshed. Mountains or other physical features may influence the fate and transport of emissions as well as the formation and distribution of ozone concentrations. The absence of any such geographic or topographic features may also be a relevant consideration in selecting boundaries for a given area.

The EPA used geography/topography analysis to evaluate the physical features of the land that might affect the airshed and, therefore, the distribution of ozone over the area. Figure 13 provides an illustration of the topographical features in the area of analysis.

Figure 13. Topographic illustration of the physical features



There are two geographic features of this region that can affect airflow in the air of analysis. The impact of the Utah and Great Salt Lakes to the west and northwest of the urban centers are discussed in the previous section on meteorology. The impact of the mountain ranges is also briefly discussed on that section. The

State's analysis in their TSD provided with their boundary recommendation provides a thorough discussion of the impact of the mountain ranges and is included in italicized text below.

> *The Wasatch Front is located along the eastern edge of the Great Basin. The Wasatch Range, extending from near the Idaho border to Mt. Nebo at the southern tip of the Northern Rocky Mountains, is a formidable obstacle to surface air mass movement to and from the east. The Wasatch Mountains rise abruptly to elevations of between 4,000 to 6,000 feet above the valley floor and help to define the Wasatch Front urban areas from Brigham City on the north to the numerous metropolitan areas in Utah County on the south. These valleys are bound on the West by the Great Salt Lake in the north and the Oquirrh Mountains, which also rise 4,000 to 5,000 feet above the valley floor, in the south. In an area of flat terrain one would expect an air mass to gradually be transported in a direction consistent with the prevailing air flow. Conversely, in an area of mountainous terrain, as is the case of the valleys along the Wasatch Front, one would expect the terrain to define the air mass boundaries and movement. With prevailing winds from the west through the north, the high terrain with its bowl shaped valleys that open to the north and west routinely functions to block any eastward horizontal movement of a stagnant air mass. In effect, the local topography actually contains stagnant air masses within these valleys.*
>
> *As discussed in the meteorology section, it has been found in several studies that concentrations of ozone trapped in large mountain valleys along the Wasatch Front, such as the Salt Lake Valley and Utah Valley, actually move horizontally within or in and out of the valleys with the diurnal mountain-valley flow. In the Salt Lake Valley, for instance, the nighttime flow generally moves the air to the northwest over the eastern portion of the Great Salt Lake while the daytime flow moves the same air back southeastward into the valley where it is contained by the Wasatch Range. In Utah Valley, the air is more contained and generally moves westward over Utah Lake in the evening and eastward during the day. In some instances, however, the air mass in either the Salt Lake Valley or Utah Valley has moved north or south to affect the other valley. In the region north of Salt Lake City, air masses have a tendency to move both north and south along the Wasatch Front, as well as east and west with the diurnal flow.*
>
> *... much of the eastern area of the Wasatch Front counties is at a much higher elevation than the adjacent western valleys, and should generally not experience the high concentrations of ozone produced in these urban valleys.*

The EPA agrees with Utah's assessment that the geography of the region makes trapping of local pollutants likely under summer stagnation events. Notably, the Wasatch mountain range prevents ozone from impacting the higher elevation, eastern portions of Weber and Utah Counties. The Traverse Range mountains divide the Salt Lake Valley and Utah Valley; which roughly corresponds with the boundary between the proposed Northern and Southern Wasatch front nonattainment areas.

Factor 5: Jurisdictional boundaries

Once the geographic extent of the violating area and the nearby area contributing to violations is determined, the EPA considered existing jurisdictional boundaries for the purposes of providing a clearly defined legal boundary to carry out the air quality planning and enforcement functions for nonattainment areas. In defining the boundaries of the intended nonattainment areas, the EPA considered existing jurisdictional boundaries, which can provide easily identifiable and recognized boundaries for purposes of implementing the NAAQS. Examples of jurisdictional boundaries include, but are not limited to: counties, air districts, areas of Indian country, metropolitan planning organizations, and existing nonattainment areas. If an existing jurisdictional boundary is used to help define the nonattainment area, it must encompass all of the area that has been identified as meeting the nonattainment definition. Where existing jurisdictional boundaries are not adequate or appropriate to describe the nonattainment area, the EPA considered other clearly defined and permanent landmarks or geographic coordinates for purposes of identifying the boundaries of the intended designated areas.

The State's analysis in their TSD provided with their boundary recommendation provides an explanation of why jurisdiction supports the State's recommendation that the Wasatch Front be designated as two separate nonattainment areas.

> *Within the Salt Lake City-Provo-Orem CSA there are three MSAs and two distinct metropolitan planning organizations (MPO) that carry out transportation planning for those MSAs. Wasatch Front Regional Council is the MPO that carries out regional transportation planning in Salt Lake, Tooele, Davis, Weber, Morgan, and Box Elder counties. The Mountainland Association of Governments (MAG) is the MPO responsible for transportation planning in Utah County. These two areas are also designated as two separate nonattainment areas for $PM_{2.5}$. Designating all of these counties as one nonattainment area would create major hurdles for MAG and WFRC within the transportation planning and conformity requirements and obligations under the Act.*

Conclusion for Wasatch Front Area

Based on the assessment of factors described above, the EPA does not intend to modify Utah's recommendation to designate two separate areas with the boundaries recommended by the state: The Northern Wasatch Front area and the Southern Wasatch Front area. The EPA has concluded that the following counties meet the CAA criteria for inclusion in the intended Northern Wasatch Front nonattainment area: all of Davis and Salt Lake Counties, and portions of Weber and Tooele Counties. The EPA has also concluded that a portion of Utah County meets the criteria for inclusion in the intended Southern Wasatch front nonattainment area. These are the same counties included in, and the same boundaries for the Northern Wasatch Front and Southern Wasatch Front nonattainment areas for the 2006 $PM_{2.5}$ NAAQS - with the exception that no portion of Box Elder County would be included as part of the Northern Wasatch Front area for the 2015 ozone NAAQS.

The air quality monitors in Salt Lake, Davis, Utah, and Weber Counties indicate violations of the 2015 ozone NAAQS based on the 2016 design values, therefore all or portions of these counties are included in the intended nonattainment areas. Tooele County does not have a monitor with complete 2014-2016 data, but the EPA has concluded that a portion of the county contributes to the ozone concentrations measured at monitors in violation of the 2015 ozone NAAQS. This conclusion is reached based on the significant number of back trajectories from that area to downwind violating monitors on days that those monitors are exceeding the NAAQS. On-road mobile and area sources from that area in Tooele County account for much of the VOCs and NO_x emitted in the County. That area also includes the more densely populated urban area of the county which is well integrated with the counties with violating monitors based on commuting patterns. The great majority (more than 85%) of Tooele County's population is contained within the area EPA intends to include in the Northern Wasatch Front nonattainment area. All of the areas the state has recommended and that the EPA intends to include in the two designated nonattainment areas are within Utah Valley and the valleys along the eastern and southern shores of the Great Salt Lake. The EPA does not intend to modify the State's recommendation not to include the portions of Utah and Weber County that are at higher elevations in the Wasatch Mountain range. As discussed, high ozone concentrations are generally found at the lower elevations while the mountain range prevents ozone, and ozone precursors from moving into eastern, higher elevation portions of counties. Moreover, we note that these portions of the counties are relatively rural, have low VMT, and do not contain any major sources.

Although Box Elder County was included within the 2006 $PM_{2.5}$ nonattainment boundary, the EPA finds sufficient evidence to exclude Box Elder from the 2015 ozone nonattainment boundary. The county includes two monitors that are attaining the 2015 ozone NAAQS. Although the EPA finds that the county contains emissions of ozone precursors from point, area, and mobile sources, the back trajectory analysis indicates that meteorological conditions result in these emissions infrequently influencing violating monitors within the proposed nonattainment area. Furthermore, commuting information shows that relatively few (approximately 11,000) people commute from Box Elder County into a county with a violating monitor.

Finally, the EPA does not intend to include Summit, Juab, Wasatch, and Morgan Counties. All of these areas have low populations (less than 40,000) and population densities less than 25 per square mile. They also have significantly lower emissions than the counties and partial counties EPA intends to include in the nonattainment area. Furthermore, topographic obstacles (Wasatch Mountains), as well as meteorology, prevent emissions in these areas from influencing violating monitors.

The EPA finds that the weight-of-evidence presented through the five-factor analysis supports the State's recommended boundaries for the Southern Wasatch Front and Northern Wasatch Front nonattainment areas for the 2015 ozone NAAQS. The EPA concludes that designating the nonattainment boundaries as proposed will support Utah's ability to focus resources on the emission sources and areas that most strongly contribute to the ozone problem along the Wasatch Front.

3.2 Technical Analysis for Uinta Basin

This technical analysis identifies the areas with monitors that violate the 2015 ozone NAAQS. It also provides EPA's evaluation of these areas and any nearby areas to determine whether those nearby areas have emissions sources that potentially contribute to ambient ozone concentrations at the violating monitors in the area, based on the weight-of-evidence of the five factors recommended in the EPA's ozone designations guidance and any other relevant information. In developing this technical analysis, the EPA used the latest data and information available to the EPA (and to the states and tribes through the Ozone Designations Mapping Tool and the EPA Ozone Designations Guidance and Data web page).[11] In addition, the EPA considered any additional data or information provided to the EPA by states or tribes.

The EPA evaluated emissions, air quality, and other information for counties in the Uinta Basin in Utah. Based on existing air quality studies (discussed later) – ozone production in the basin is a highly localized phenomenon. The Uinta basin is a winter ozone area, where violating ozone concentrations are dependent

[11] The EPA's Ozone Designations Guidance and Data web page can be found at *https://www.epa.gov/ozone-designations/ozone-designations-guidance-and-data.*

on stagnant winter conditions associated with strong temperature inversions. These conditions limit the influence of areas outside the topographic Uinta Basin. The Uinta Basin lies primarily within Uintah and Duchesne counties of Utah. The role of winter temperature inversions in producing ozone near the basin floor means that contributing emission sources are those at relatively low elevations within the basin. The only low elevation portion of the basin outside Uintah and Duchesne counties lies along the White River in Rio Blanco County, Colorado. The area of analysis was determined to be Uintah County and Duchesne County in Utah, and the White River valley in Rio Blanco County, Colorado. Uintah County is in the Vernal CBSA, while Duchesne and Rio Blanco Counties are not in CBSAs.

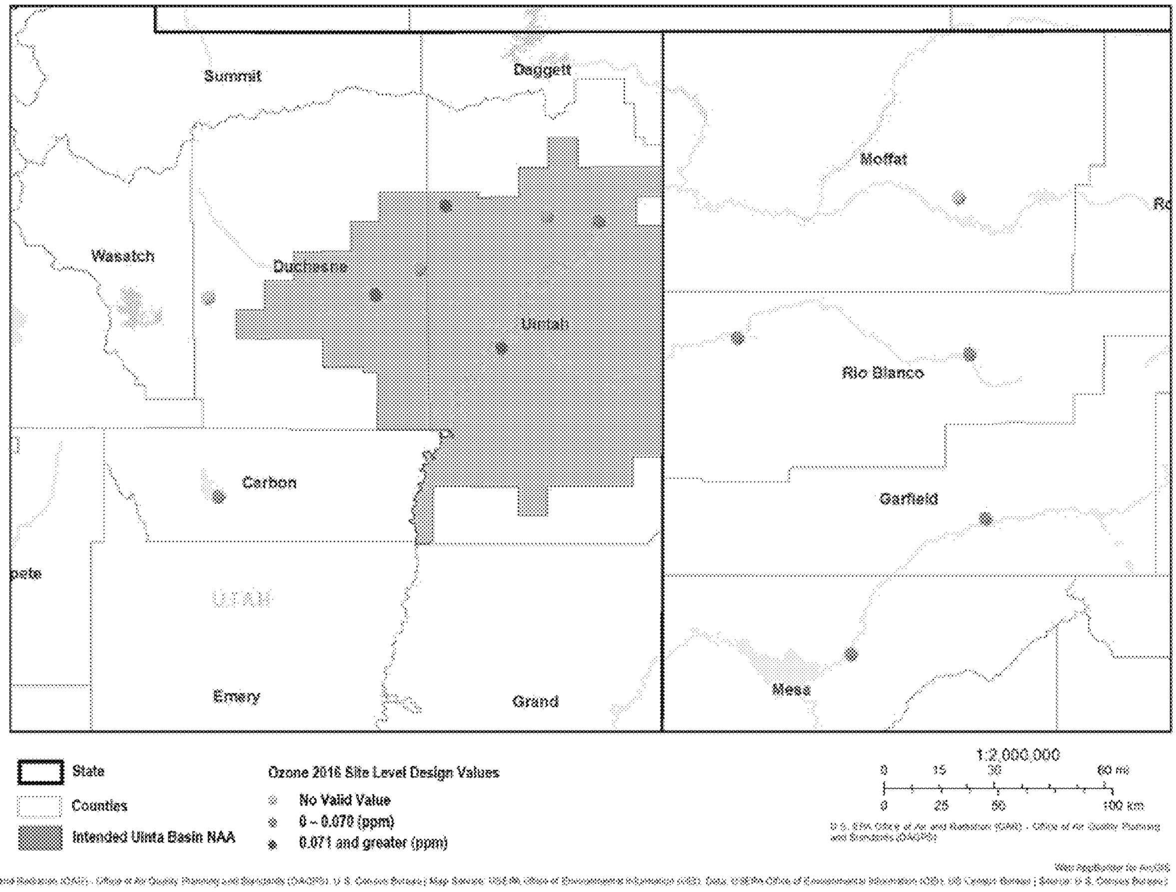
The five factors recommended in the EPA's guidance are:

1. Air Quality Data (including the design value calculated for each Federal Reference Method (FRM) or Federal Equivalent Method (FEM) monitor;
2. Emissions and Emissions-Related Data (including locations of sources, population, amount of emissions, and urban growth patterns);
3. Meteorology (weather/transport patterns);
4. Geography/Topography (including mountain ranges or other physical features that may influence the fate and transport of emissions and ozone concentrations); and
5. Jurisdictional Boundaries (e.g., counties, air districts, existing nonattainment areas, areas of Indian country, Metropolitan Planning Organizations (MPOs)).

As described in Section 1, the state of Utah recommended that only the portion of the Uinta Basin in townships at elevations below 6,000 feet be designated nonattainment, while the Ute Indian Tribe recommended that only the portion of the Uinta Basin around the Ouray monitor be designated nonattainment.

Figure 14 is a map of the EPA's intended nonattainment boundary for the Uinta Basin area. The map shows the location of the ambient air quality monitors, county, and other jurisdictional boundaries.

Figure 14. EPA's Intended Nonattainment Boundaries for the Uinta Basin



The EPA must designate as nonattainment any area that violates the NAAQS and any nearby areas that contribute to the violation in the violating area. Uintah and Duchesne Counties have monitors in violation of the 2015 ozone NAAQS, therefore these counties (or portions of these counties) are included in the intended nonattainment area. As previously noted and as explained in more detail in the section discussing meteorology, the EPA determined based on existing air quality studies completed in the Uinta Basin, that sources in surrounding counties do not contribute to the violating area because of the unique geographic features of the area and the winter temperature inversion meteorology. The following sections describe the five factor analysis for the area within the Uinta Basin to determine the areas within the basin that are contributing to a violation of the 2015 ozone NAAQS. While the factors are presented individually, they are not independent. The five factor analysis process carefully considers the interconnections among the different factors and the dependence of each factor on one or more of the others, such as the interaction between emissions and meteorology for the area being evaluated.

Factor Assessment

Factor 1: Air Quality Data

The EPA considered 8-hour ozone design values in ppm for air quality monitors in the area of analysis based on data for the 2014-2016 period (i.e., the 2016 design value, or DV). This is the most recent three-year period with fully-certified air quality data. The design value is the 3-year average of the annual 4th

highest daily maximum 8-hour average ozone concentration.[12] The 2015 NAAQS are met when the design value is 0.070 ppm or less. Only ozone measurement data collected in accordance with the quality assurance (QA) requirements using approved (FRM/FEM) monitors are used for NAAQS compliance determinations.[13] The EPA uses FRM/FEM measurement data residing in the EPA's Air Quality System (AQS) database to calculate the ozone design values. Individual exceedances of the 2015 ozone NAAQS that the EPA determines have been caused by an exceptional event that meets the administrative and technical criteria in the Exceptional Events Rule[14] are not included in these calculations. Whenever several monitors are located in a county (or designated nonattainment area), the design value for the county or area is determined by the monitor with the highest valid design value. The presence of one or more violating monitors (i.e. monitors with design values greater than 0.070 ppm) in a county or other geographic area forms the basis for designating that county or area as nonattainment. The remaining four factors are then used as the technical basis for determining the spatial extent of the designated nonattainment area surrounding the violating monitor(s) based on a consideration of what nearby areas are contributing to a violation of the NAAQS.

The EPA identified monitors where the most recent design values violate the NAAQS, and examined historical ozone air quality measurement data (including previous design values) to understand the nature of the ozone ambient air quality problem in the area. Eligible monitors for providing design value data generally include State and Local Air Monitoring Stations (SLAMS) and tribal air monitoring stations that are operated in accordance with 40 CFR part 58, appendix A, C, D and E and operating with an FRM or FEM monitor. These requirements must be met in order to be acceptable for comparison to the 2015 ozone NAAQS for designation purposes. All data from Special Purpose Monitors (SPMs) using an FRM or FEM are eligible for comparison to the NAAQS, subject to the requirements given in the March 28, 2016 Revision to Ambient Monitoring Quality Assurance and Other Requirements Rule (81 FR 17248).

The 2014-2016 design values for counties in the Uinta Basin are shown in Tables 6 and 7 (State and Tribal jurisdiction). The design values shown reflect the concurrence on an exceptional event demonstration made by the Ute Indian Tribe of the Uintah and Ouray Reservation impacting ozone data collected on June 8 and 9, 2015. The Ute Tribe successfully showed that the ozone exceedances at tribal monitors on those days were caused by a stratospheric intrusion exceptional event.[15]

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[12] The specific methodology for calculating the ozone design values, including computational formulas and data completeness requirements, is described in 40 CFR part 50, appendix U.

[13] The QA requirements for ozone monitoring data are specified in 40 CFR part 58, appendix A. The performance test requirements for candidate FEMs are provided in 40 CFR part 53, subpart B.

[14] The EPA finalized the rule on the Treatment of Data Influenced by Exceptional Events (81 FR 68513) and the guidance on the Preparation of Exceptional Events Demonstrations for Wildfire Events in September of 2016. For more information, see *https://www.epa.gov/air-quality-analysis/exceptional-events-rule-and-guidance.*

[15] The EE was acted on by EPA on June 7, 2017 with concurrence from Sarah Dunham, Acting Assistant Administrator for the Office of Air and Radiation.

Table 6. Air Quality Data – Utah and Colorado State Land (all values in ppm)

County, State	State Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Rio Blanco, CO	No	08-103-0006 (Rangely)	**0.063**	0.062	0.066	0.061
Duchesne, UT	Yes (partial)	49-013-0002 (Roosevelt)	N/A	0.062	0.060	0.081
Uintah, UT	Yes (partial)	49-047-1002 (Dinosaur NM)	0.068	0.064	0.067	0.075
		49-047-1003 (Old Vernal)	N/A	0.062	N/A	N/A
		49-047-1004 (New Vernal)	N/A	N/A	0.064	0.073

The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Table 7. Air Quality Data – Ute Indian Tribal Land (all values in ppm)[a]

County, State	Tribe Recommended Nonattainment?	AQS Site ID	2014-2016 DV	2014 4th highest daily max value	2015 4th highest daily max value	2016 4th highest daily max value
Duchesne, UT	No	49-013-7011 (Myton)	**0.072**	0.067	0.065	0.085
Uintah, UT	No (or partial)	49-047-2002 (Redwash)	N/A	0.061	0.066	0.083
		49-047-2003 (Ouray)	**0.080**	0.079	0.067	0.096
		49-047-7022 (Whiterocks)	0.071	0.064	0.068	0.081

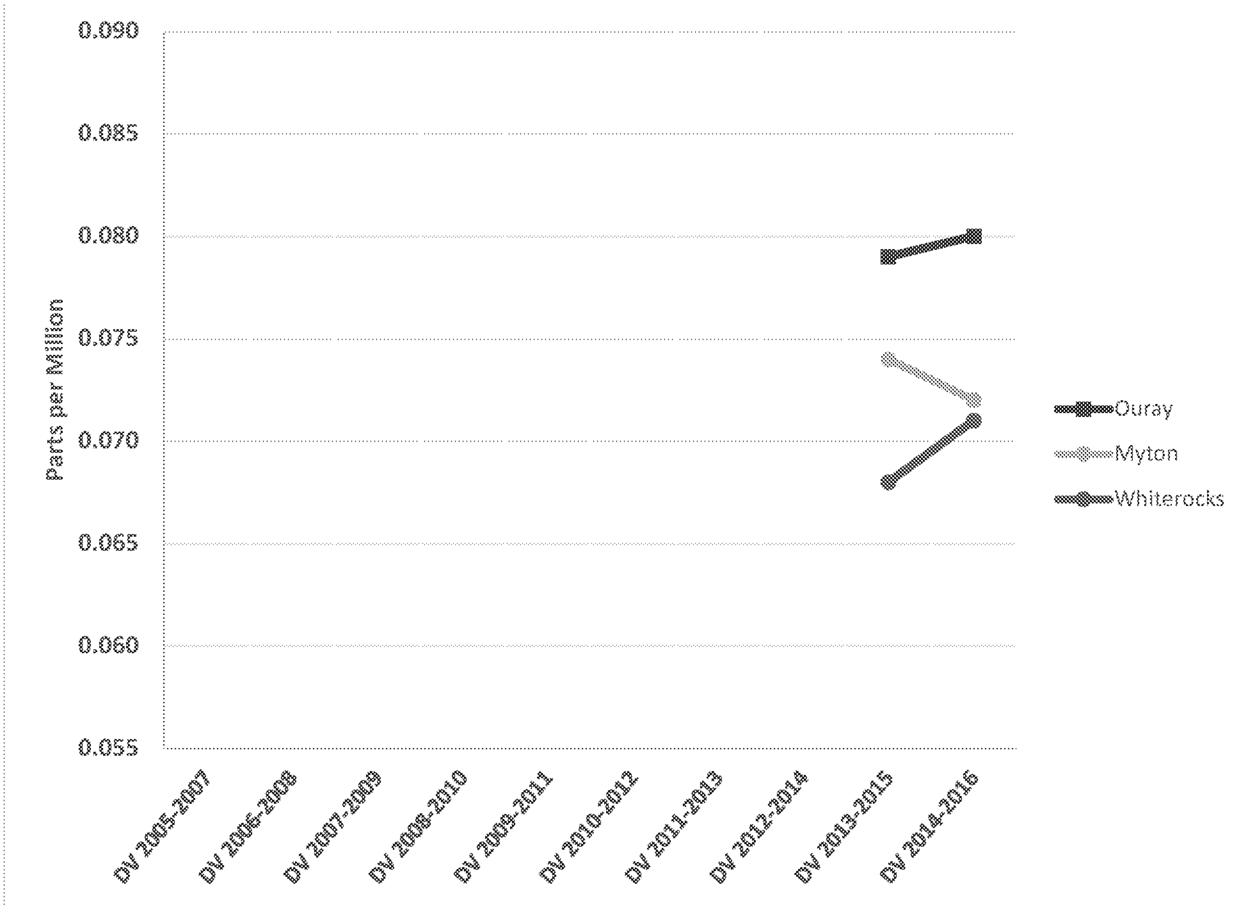
The highest design value in each county is indicated in bold type.
N/A means that the monitor did not meet the completeness criteria described in 40 CFR, part 50, Appendix U, or no data exists for the county.

Monitors within Uintah and Duchesne Counties on tribal land show violations of the 2015 ozone NAAQS; therefore, these counties with violating monitors are included in whole or in part in the intended nonattainment area. The Rangely monitor in Rio Blanco County is well below the NAAQS with a design value of 0.063 ppm.

Figure 14, shown previously, identifies the Uinta Basin intended nonattainment area and the violating monitors. Tables 6 and 7 identify the design values for all monitors in the area of analysis and Figure 15 shows the historical trend of design values for the violating monitors. Regulatory data collection in the Uinta Basin has only occurred since 2011. As indicated on the map, there are three violating monitors that are located at 1) the Myton site in Duchesne County, about six miles west of the community of Myton; 2) the Ouray site in Uintah County near the confluence of the Green and White Rivers, about 24 miles southeast of the town of Roosevelt; and 3) the Whiterocks site in Uintah County, twenty miles west of the town of Vernal and 1.5 miles northeast of the community of Whiterocks. Other monitors within Uintah and

Duchesne Counties have incomplete data for 2014-2016, so the EPA cannot calculate valid design values in accordance with 40 CFR part 50, appendix U.

Figure 15. Three-Year Design Values for Uinta Basin Monitors (2007-2016)



Regulatory ozone measurements showing recurring exceedances have been conducted at two monitoring sites above 6,000 feet in the Uinta Basin. The Whiterocks monitoring station of the Ute Indian Tribe of the Uintah and Ouray Reservation is at an elevation of 6,216 feet,[16] and the Rabbit Mountain/Dragon Road Prevention of Significant Deterioration (PSD) monitoring station operated by ENEFIT was at an elevation of 6,165 feet. Both have recorded exceedances of the 70 ppb ozone standard. Whiterocks recorded two exceedances in 2011 and thirteen exceedances in 2013 prior to becoming a regulatory monitor (highest recorded 8-hour average was 107 ppb on January 22, 2013). Whiterocks then recorded four regulatory exceedances in December 2013, and seven in February 2016 (highest regulatory value 86 ppb on February 12, 2016) leading to a NAAQS violation. The Rabbit Mountain/Dragon Road monitor was a regulatory PSD monitor that operated throughout 2012 and for the first half of 2013. It recorded five non-winter ozone exceedances in April-August 2012 (with a highest value of 77 ppb), and 11 exceedances in January and February of 2013 (with a high of 107 ppb on January 26, 2013).

[16] Monitor site data in the AQS database shows an elevation of 1,893 meters, or 6,211 feet. Examination of the station siting on GIS maps gives an elevation of 6,216 feet.

Based on the EPA's review of regulatory monitors in the Uinta Basin, the data shows that an elevation of 6,000 feet does not include all portions of the area violating the NAAQS and based on EPA's analysis here, it does not include all of the portions of the area contributing to violations of the NAAQS. Thus, it is not a practical upper boundary for the Uinta Basin ozone nonattainment area. Table 8 shows the elevation of the regulatory monitors in the Uinta basin, with summaries of their ozone measurements during the 2013 winter ozone study in the basin. The elevation of the highest monitor is 6,216 feet.

Table 8. Winter 2013 Ozone Monitors

Site Name	Latitude	Longitude	Elevation	Number of Daily Winter 2013 Values over 70 ppb	Winter 2013 4th High (ppb)
Dinosaur N. M.	40.4372	-109.3047	1463 m (4,800 ft)	34	113
Ouray	40.05671	-109.688108	1467 m (4,813 ft)	39	132
Myton	40.216779	-110.182742	1606 m (5,269 ft)	27	97
Roosevelt	40.2942178	-110.009732	1596 m (5,236 ft)	32	104
Vernal	40.452267	-109.510393	1605 m (5,265 ft)	23	102
Rangely, CO	40.086944	-108.761389	1655 m (5,430 ft)	13	91
Redwash	40.206291	-109.353932	1702 m (5,584 ft)	36	114
Rabbit Mountain	39.868622	-109.097302	1879 m (6,165 ft)	11	82
Whiterocks	40.483598	-109.906796	1895 m (6,216 ft)[17]	13	86

Unlike most areas where photochemical ozone production is a summertime phenomenon, the Uinta Basin is a winter ozone area. For 2013-2015, regulatory monitors in the Uinta Basin recorded 54 days above the level of the 2015 NAAQS in the months of December through March, and only four days above that level in other months (including June 8-9, 2015 mentioned earlier as stratospheric intrusion exceptional event days). For 2014-2016, regulatory monitors recorded 19 days above the standard December through March, and only those two days in June 2015 were above the standard in other months. The causes of winter ozone formation will be discussed under factor 3 (Meteorology). Overall, the air quality data support designating all or portions of Duchesne and Uintah County (including tribal lands) as nonattainment of the 2015 ozone NAAQS.

[17] Latitude, longitude and elevation are as shown in the AQS database with the exception of the elevation of the Whiterocks station, which is taken from digital map data.

Factor 2: Emissions and Emissions-Related Data

The EPA evaluated ozone precursor emissions of nitrogen oxides (NO_x) and volatile organic compounds (VOC) and other emissions-related data that provide information on areas contributing to violating monitors.

Emissions Data

The EPA reviewed data from the 2014 National Emissions Inventory (NEI). For each county in the area of analysis, the EPA examined the magnitude of large sources (NO_x or VOC emissions greater than 100 tons per year) and small point sources and the magnitude of county-level emissions reported in the NEI. These county-level emissions represent the sum of emissions from the following general source categories: point sources, non-point (i.e., area) sources, non-road mobile, on-road mobile, and fires. Emissions levels from sources in a nearby area indicate the potential for the area to contribute to monitored violations.

Table 9 provides a county-level emissions summary of NO_x and VOC (given in tons per year (tpy)) emissions for the area of analysis considered for inclusion in the intended Uinta Basin nonattainment area. As shown in the table, Uintah County contributes the majority of VOC emissions – approximately 58% of the area of analysis. Duchesne County contributes approximately 36% of the total, while Rio Blanco's county-wide VOC emissions account for about 6% of the area-wide VOC emissions. Uintah and Duchesne Counties each contribute similar amounts to the NOx emissions in the area while Rio Blanco in Colorado contributes roughly 2,500 tpy less than either of the Utah Counties.

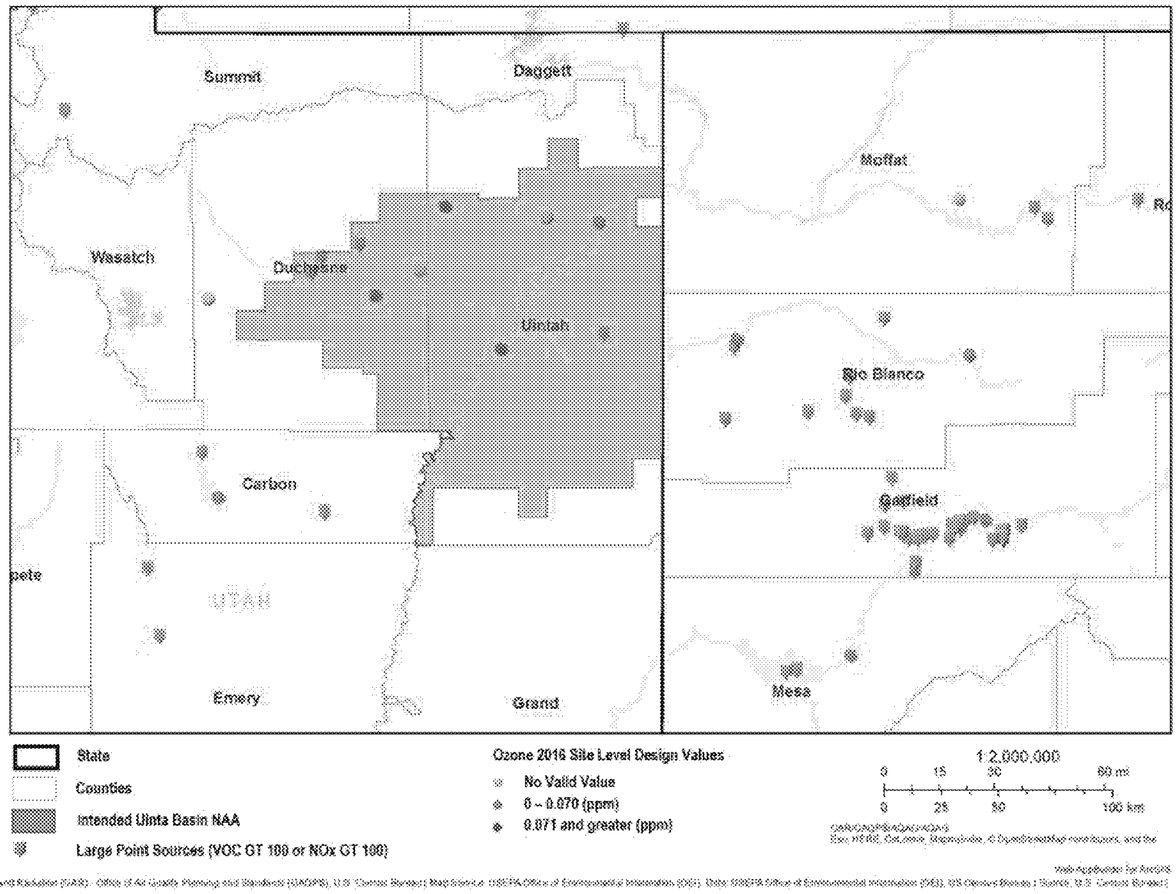
Table 9. Total County-Level NOx and VOC Emissions.

County	State Recommended Nonattainment	Total NOx (tpy)	Total VOC (tpy)
Duchesne	Yes (partial)*	9,352	55,880
Uintah	Yes (partial)*	9,116	88,592
Rio Blanco	No	6,746	9,330
	Area Wide:	25,214	153,802

* For state recommended partial counties, the emissions shown are for the entire county.

In addition to reviewing county-wide emissions of NO_x and VOC in the area of analysis, the EPA also reviewed emissions from large point sources. The location of these sources, together with the other factors, can help inform nonattainment boundaries. The locations of the large point sources are shown in Figure 16 below. The intended nonattainment boundary is also shown. In Utah, two of the four large point sources (natural gas compressor stations around Altamont in Duchesne County) are located outside the boundary recommended by the State, which includes only townships below 6,000-ft elevation. If townships below 6,250 ft are included, a third compressor station near Altamont would be within the nonattainment area. Two other large sources are within the state-recommended boundary: a compressor station at 5,870 feet; and the Bonanza power station at 5,935 feet elevation on Indian country in Uintah County. In Colorado, there are two large point sources in the western portion of Rio Blanco county which could be considered to be within the Uinta Basin (a compressor station and an oil and gas processing facility). These two facilities contribute approximately 9% and 1% of the Rio Blanco county-level NOx and VOC emissions, respectively.

Figure 16. Large Point Sources in the Area of Analysis



In addition to looking at total overall emissions and large point source emissions for the county, we also reviewed the VOC and NO_X emissions by source sector in the Uinta Basin from the 2014 National Emissions Inventory, which shows that emissions from the production segment of the oil and natural gas sector were estimated to be the largest anthropogenic contributor of VOC and NO_X emissions in the area of analysis. These sources are located on both state and tribal land. As indicated by Utah in their TSD, approximately 80 percent of oil and gas production occurs on tribal land. As shown in Figure 17 (from Utah's TSD), oil and gas development is prevalent in most of central and southern Uintah County. In Duchesne County, oil and gas development has occurred mostly in the eastern 2/3 of the county. For both Uintah and Duchesne Counties, the northern portions of the counties are undeveloped and lack any significant emission sources; and include large areas of U. S. Forest Service land.

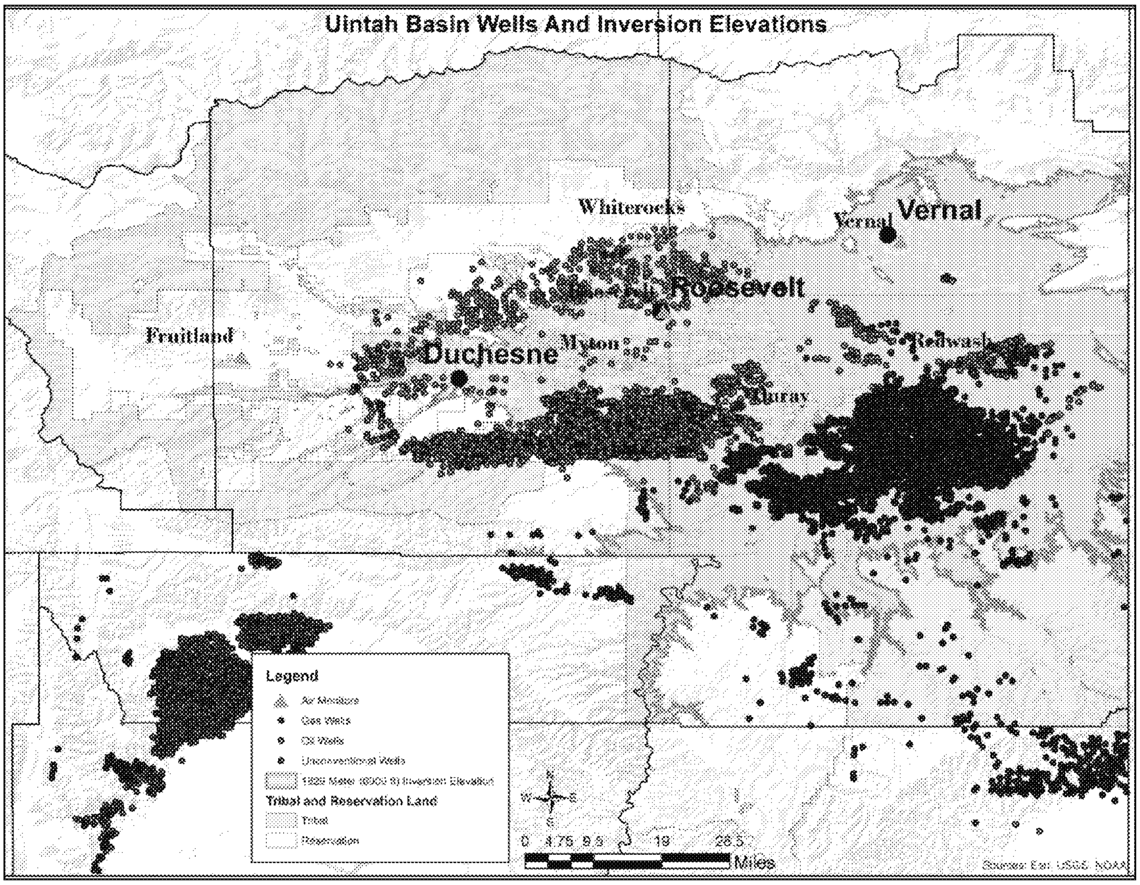
While most of these sources are located at the lower elevations in the basin, based on the information from the Utah Department of Oil, Gas, and Mining[18] and data submitted by operators in the 2014 Uinta Basin Emissions Inventory[19] (included in Version 2 of the 2014 NEI), 85 percent of facilities representing 88 percent of emissions in Uintah and Duchesne Counties are in townships below 6,000 ft in elevation. If

[18] Based on wells included in the EPA's intended boundary compared with all wells in Uintah and Duchesne Counties. The well locations were obtained from the Utah Department of Oil, Gas, and Mining

[19] Emissions information was obtained from the 2014 Uinta Basin Emissions Inventory for all sources located below 6,250 ft.

townships below 6,250 feet are included, 93 percent of all wells and 92 percent of all oil and natural gas emissions would be within the boundary.

Figure 17. Uinta Basin oil and gas wells and the State-recommended 6,000-ft elevation (blue)



Population density and degree of urbanization

In this part of the factor analysis, the EPA evaluated the population and vehicle use characteristics and trends of the area as indicators of the probable location and magnitude of non-point source emissions. These include emissions of NO_x and VOC from on-road and non-road vehicles and engines, consumer products, residential fuel combustion, and consumer services. Areas of dense population or commercial development are an indicator of area source and mobile source NO_x and VOC emissions that may contribute to violations of the NAAQS. Table 10 shows the population, population density, and population growth information for each county in the area of analysis.

Table 10. Population and Growth

County Name	State Recommended Nonattainment	2010 Population	2015 Population	2015 Populations Density (per sq. mi.)	Absolute Change in Population (2010-2015)	Population % Change (2010-2015)

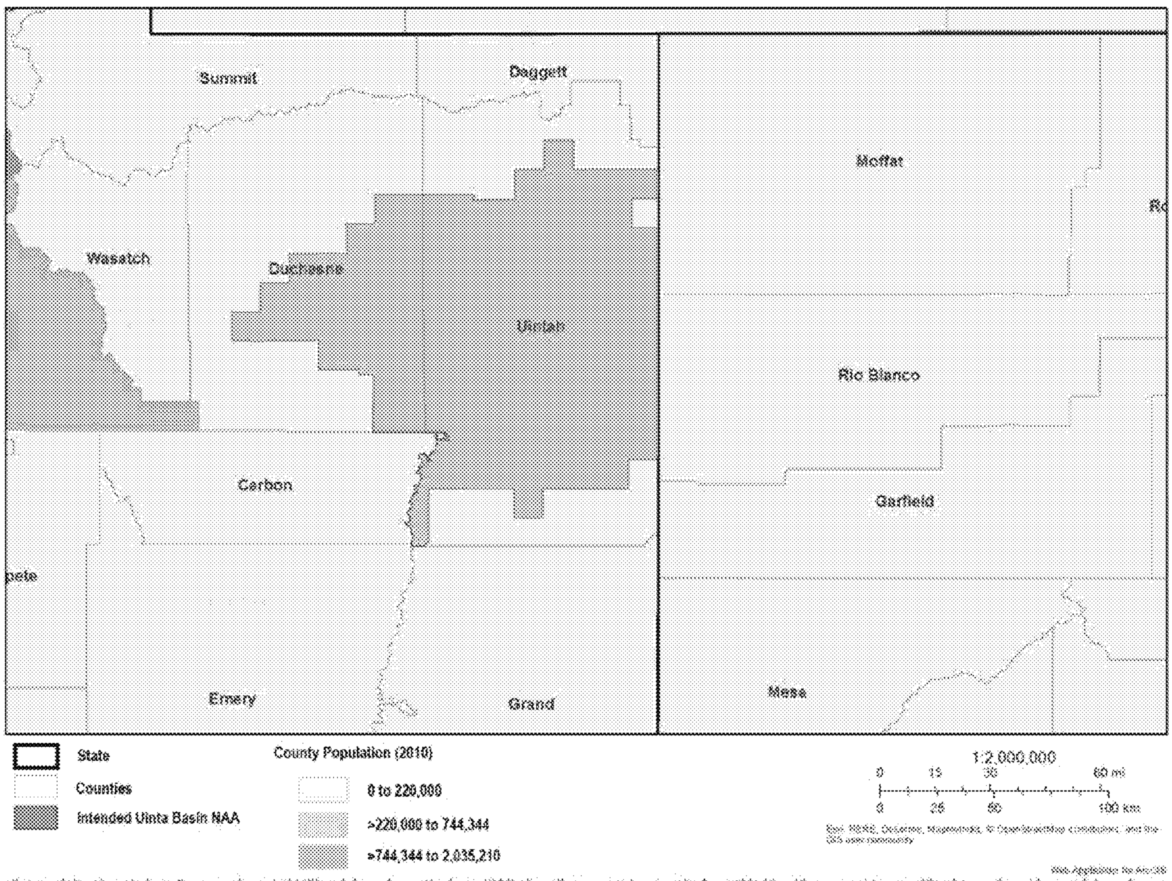
Uintah County	Yes (partial)*	32,588	37,928	8	5,340	16
Duchesne County	Yes (partial)*	18,607	20,862	6	2,255	12
Rio Blanco	No	6,666	6,571	2	-95	-1

* For state recommended partial counties, the data are for the entire county.

Source: U.S. Census Bureau population estimates for 2010 and 2015. www.census.gov/data.html.

The Uinta Basin is predominantly rural and contains a sparse population (see Figure 18). Although there has been a significant population change for Uintah and Duchesne counties, because of the sparse population, the absolute change in population is relatively small. Rio Blanco County has seen a one percent decline in population between 2010 and 2015. Most of the largest population centers are located in the basin at the lower elevations: Myton, Roosevelt, Duchesne, Fort Duchesne, and Rangely.

Figure 18. County-Level Population



Traffic and Vehicle Miles Travelled (VMT)

The EPA evaluated the commuting patterns of residents, as well as the total vehicle miles traveled (VMT) for the area of analysis. In combination with the population/population density data and the location of main transportation arteries, this information helps identify the probable location of non-point source emissions. A county with high VMT and/or a high number of commuters is generally an integral part of an urban area and high VMT and/or high number of commuters indicates the presence of motor vehicle emissions that may contribute to violations of the NAAQS. Rapid population or VMT growth in a county on the urban perimeter may signify increasing integration with the core urban area, and thus could indicate that the associated area source and mobile source emissions may be appropriate to include in the nonattainment area. In addition to VMT, the EPA evaluated worker data collected by the U.S. Census Bureau[20] for the counties in the area of analysis. Table 11 shows the traffic and commuting pattern data, including total VMT for each county in the area of analysis, number of residents who work in each county, number of residents that work in counties with violating monitor(s), and the percent of residents working in counties with violating monitor(s). The data in Table 11 are from 2014.

Table 11. Traffic and Commuting Patterns.

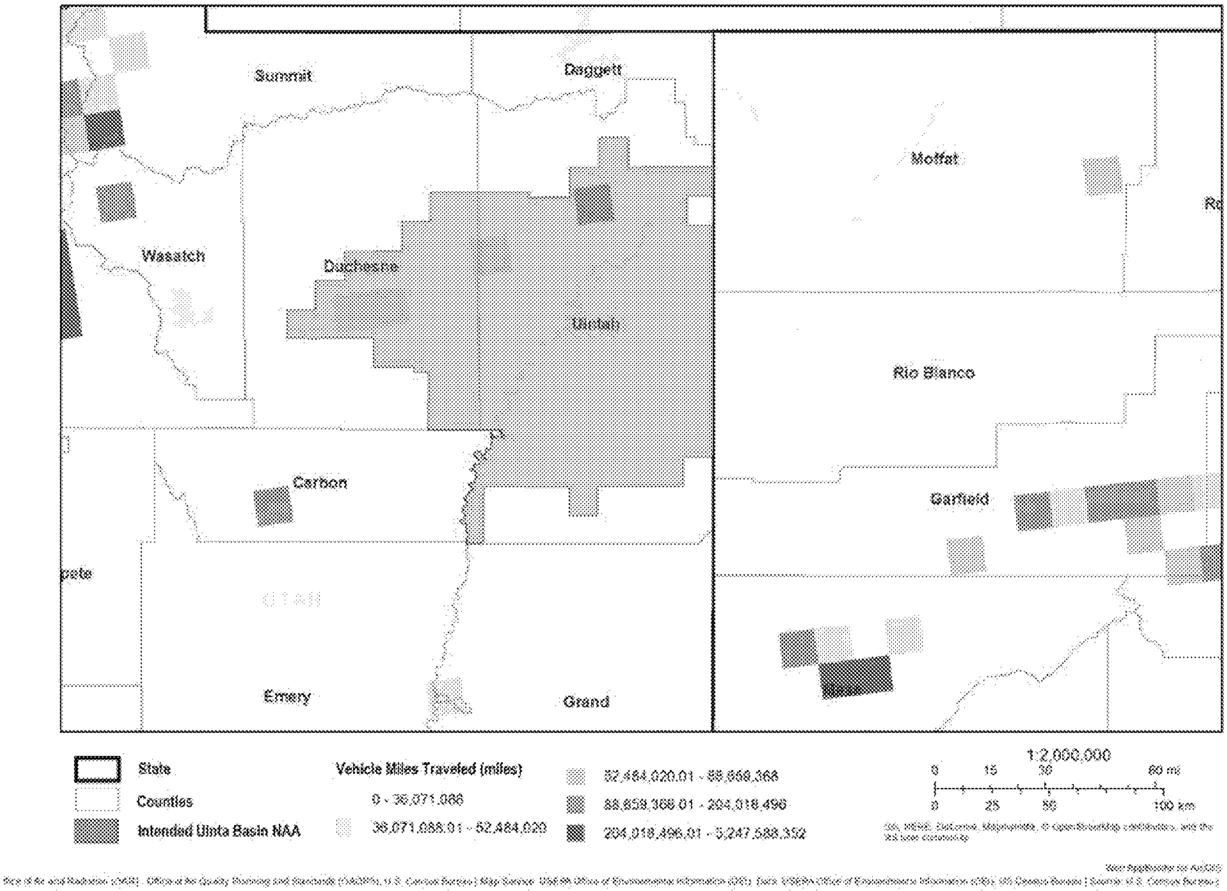
County	State Recommended Nonattainment?	2014 Total VMT (Million Miles)	Number of County Residents Who Work	Number Commuting to or Within Counties with Violating Monitor(s)	Percentage Commuting to or Within Counties with Violating Monitor(s)
Uintah	Yes (partial)*	428	16,723	11,710	70.0%
Duchesne	Yes (partial)*	283	8,981	5,789	64.5%
Rio Blanco	No	138	2,985	63	2.1%
	Total:	849	28,689	17,562	61.2

* For state recommended partial counties, the data provided are for the entire county.
Counties with a monitor(s) violating the NAAQS are indicated in bold.

To show traffic and commuting patterns, Figure 19 overlays twelve-kilometer gridded VMT from the 2014 NEI with a map of the transportation arteries.

[20] The worker data can be accessed at: http://onthemap.ces.census.gov/.

Figure 19. Twelve Kilometer Gridded VMT (Miles) Overlaid with Transportation Arteries



As shown in Figure 19 and Table 11, commuting patterns and mobile source emissions are not large components of the VOC and NO_x emissions inventory (0.2 percent and 10 percent, respectively) in the basin and are consistent with the rural character of the region.

Factor 3: Meteorology

Evaluation of meteorological data helps to assess the fate and transport of emissions contributing to ozone concentrations and to identify areas potentially contributing to the monitored violations. Results of meteorological data analysis may inform the determination of nonattainment area boundaries.

The Uinta Basin winter meteorology combines with the basin's topography to create elevated ozone concentrations. The bowl shaped basin is surrounded on each side by much larger mountain ranges with varying heights from over 7,500 to 13,000 feet. In environments such as this one, cooler, denser air becomes trapped in the basin when warmer air overrides the area during high pressure events. Subsidence from high pressure ridges and low surface winds in a stable environment do not allow for the normal atmospheric mixing (that would occur with positive lapse rates) during these events; only cooler temperatures aloft, high winds, or surface warming can break down an inversion and allow pollutants to mix out of the basin.

The ground level inversion in the Uinta Basin is persistent with snow cover. The sun's rays cannot reach the ground covered by snow to warm the surface. At night, cold, downsloping winds from the surrounding mountains can strengthen the inversion. The super-stable atmosphere allows emissions to accumulate, and the sunny conditions during the daytime let photochemical reactions take place. Only emissions with enough heat, plume velocity, or stack height can escape the inversion, depending on the boundary layer height, and enter the unstable atmosphere above the inversion. Many sources in the Uinta Basin emit VOC's with low heat, velocity, and stack heights, and a large portion of VOC emissions come from fugitive emissions and leaks. Taking into account atmospheric dispersion and turbulent flow plume dynamics for the majority of sources in the Uinta Basin, emissions do not have an opportunity to escape the boundary layer under the temperature inversion. Because of the meteorological factors that cause the boundary layer height to oscillate, and nighttime downslope winds, no static altitude of an inversion height throughout the basin always applies, and emissions above a given elevation can descend to lower elevations with nighttime orographic (downslope) flow.

Unique meteorological and topographic features result in the winter conditions that lead to ozone violations in the Uinta Basin. These unique features are strong and persistent temperature inversions forming over snow covered ground, elevated terrain completely surrounding a low basin, and abundant ground level emissions of ozone precursors from widely dispersed oil and gas production emission sources. Data from recent wintertime research campaigns was evaluated to determine how meteorology impacts the geographic extent of high ozone concentrations and the ability of emissions at a given elevation to migrate and produce ozone at other elevations (higher or lower than the emission point).

As noted in the Wasatch Front discussion, the HYSPLIT model is traditionally used to evaluate the impact of meteorology on sources and impacted monitors. However, in the case of the Uinta Basin, the complex metrological events that result in high ozone events are beyond the capabilities of the HYSPLIT tool. Uinta Basin winter ozone forms under strong, shallow temperature inversions. The strong temperature inversions decouple surface winds, which control movement of locally emitted ozone precursors and ozone from the regional meteorology present above the inversion level. HYSPLIT relies on generalized, gridded meteorological data, and the gridded data files HYSPLIT relies upon to predict air movement are unable to accurately represent the local surface winds measured by weather stations. Consequently, the EPA relied on air quality studies completed in the Uinta Basin to determine the effect of meteorology in determining an appropriate nonattainment area boundary, rather than HYSPLIT trajectories.

Wintertime ozone is formed in cold periods, generally with snow cover and under clear skies. Utah described the impact of winter weather on ozone formation.[21]

> *The wintertime photochemical ozone production in the Basin requires snow on the ground, a shallow boundary layer, stagnation and a persistent temperature inversion capping the shallow ozone production layer. The snow helps to keep the surface cold, reinforcing the production and maintenance of the temperature inversion. Snow also reflects daytime solar radiation that enhances photochemical ozone production. The inversion layer traps the emissions from the wells, pipelines,*

[21] UT TSD, p. 48-49.

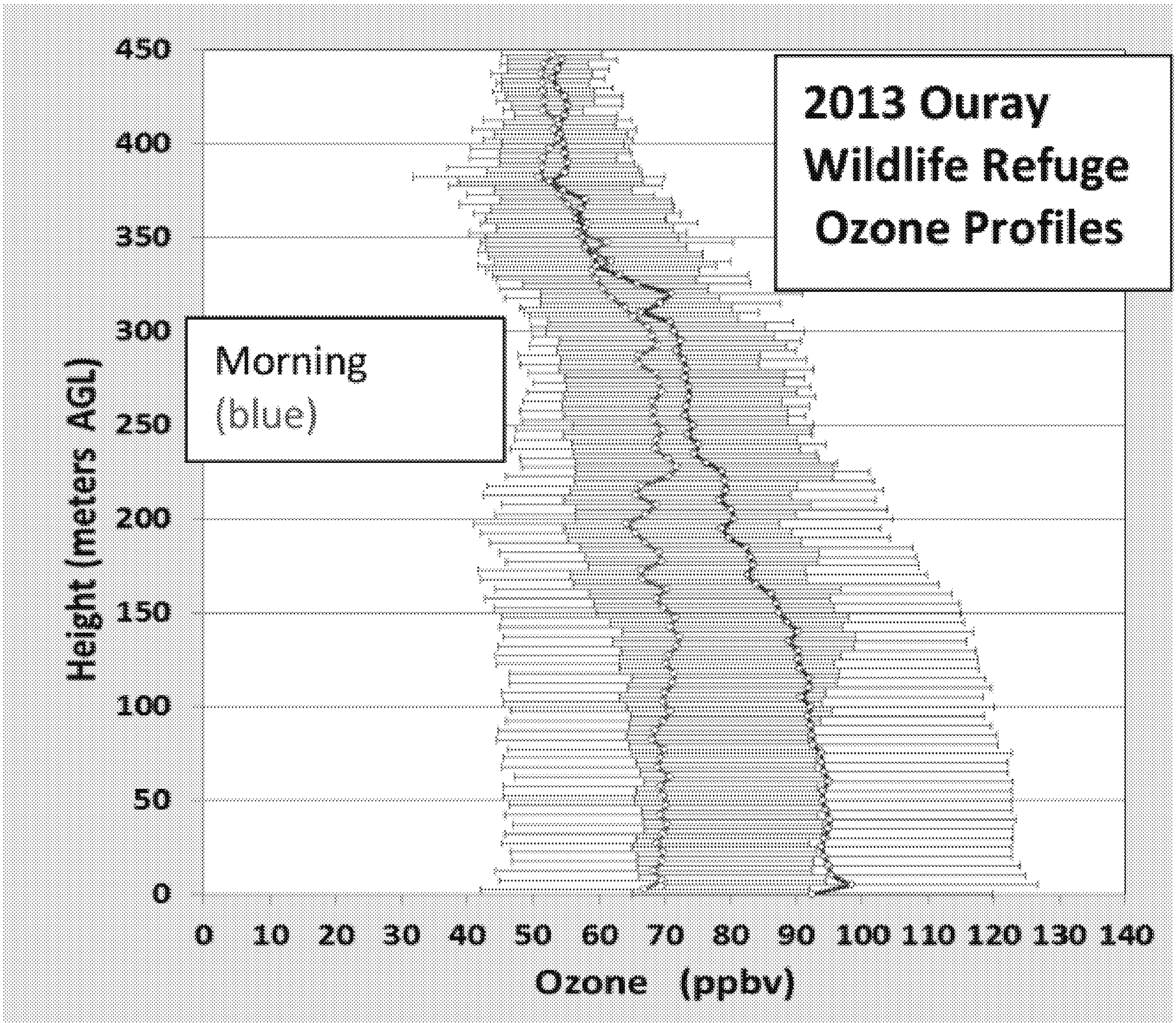
> *and compressor stations in a shallow layer where the rapid photochemical ozone production occurs.*

Utah bases its recommendation for an upper elevation limit on results from the 2013 Uinta Basin Winter Ozone Study.

> *This vertical limit to the high ozone and the chemistry that forms high ozone was observed at 1,700 meters (5,577 feet) during one of the strongest winter inversions studied and experienced the highest ozone values recorded (UBOS 2013).*

Ozonesondes were launched primarily from the Ouray National Wildlife Refuge, at 1,430-meter elevation (4,692 feet) and from Fantasy Canyon, at 1,470 meters (4,823 feet). A few sondes were launched from the Horsepool site, at 1,569 meters (5,148 feet). In general, the ozonesondes found surface ozone was elevated through the lower 300 meters (984 feet) of the atmosphere on high ozone days. Averages and extremes of ozone concentration as a function of ozonesonde height at the Ouray National Wildlife Refuge site from the 2013 winter study are shown in Figure 20.

Figure 20. Summary plot of the 2013 average ozone mixing ratio and standard deviations measured at all sites during morning (between sunrise and local noon, in blue) and afternoon (noon to sunset, in red). Note the large range of ozone concentrations in 2013 and the large photochemical production of ozone in the afternoons.[22]

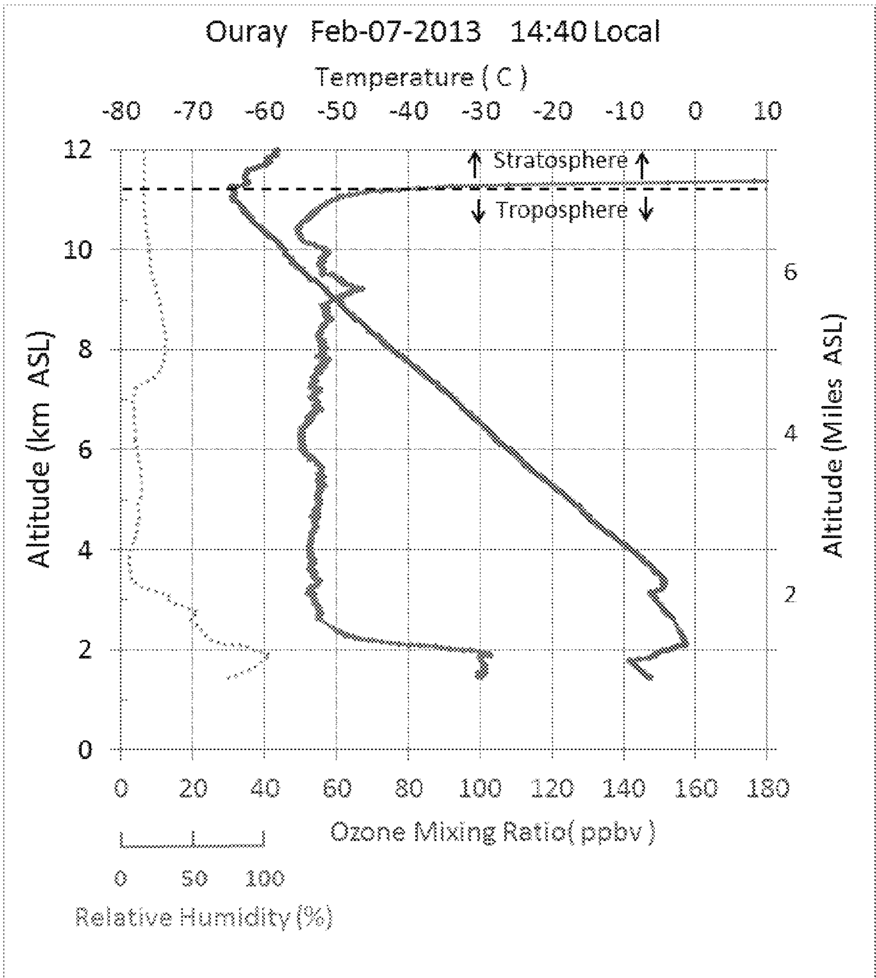


The dominant meteorological feature influencing the frequency and severity of ozone exceedances in the Uinta Basin are persistent wintertime temperature inversions. Figure 21 shows a typical ozonesonde sounding, from 2:40 pm on February 7, 2013 at the Ouray National Wildlife Refuge site (surface elevation of 1,430 m, or 4,692 feet). It shows a surface temperature of about -7 °C (19.4 °F), with temperature decreasing to about -9 °C (15.8 °F) at the top of the temperature inversion. Air temperature then increases above the top of the inversion layer to a high of about -2 °C (28.4 °F) at an altitude of about 2,100 m (6,890

[22] Final Report, 2013 Uinta Basin Winter Ozone Study, March 2014, ENVIRON (ed.), Section 8, Tethered Ozonesonde and Surface Ozone Measurements in the Uinta Basin, Winter 2013, p. 8-9; https://deq.utah.gov/locations/U/uintahbasin/ozone/docs/2014/06Jun/UBOS2013FinalReport/UBOS_2013Sec_8_NOAAsondes.pdf.

feet). Above that peak temperature, temperatures decrease, until the surface temperature of -7 ° is reached again at an altitude of about 3,200 m (10,500 feet) at the base of a second weak temperature inversion. The temperature inversions, with colder air below warmer air, limit the vertical transport of pollutants, trapping pollutants below the inversion, and preventing transported pollutants above the inversion from mixing downward to the surface. The ozonesonde also shows elevated ozone at 100 ppb extending from the surface to the top of the surface temperature inversion at about 1,900 m (6,234 feet), and then shows well mixed tropospheric background ozone at 50 to 55 ppb from an altitude of 2,500 m (8,200 feet) to the tropopause at about 10,500 m (34,450 feet).

Figure 21. Free Flying Ozonesonde Data, Tropospheric Portion, Ouray, 2:40 pm MST, February 7, 2013[23]



The Whiterocks monitor, which is in violation of the ozone standard using 2014-2016 data, is a good indicator for transportation and meteorological factors that affect ozone readings at ground levels above

[23] NOAA Earth Systems Research Laboratory, Global Monitoring Division, Ozonesonde Archive, Field Projects, Uintah 2013, Ouray_Feb07_2013_FreeFlyingBalloon_Troposphere.png, ftp://ftp.cmdl.noaa.gov/ozwv/Ozonesonde/Field%20Projects/Uintah/UINTAH%202013/4_OzoneSonde_FreeFlight_Balloons/

6,000 feet. Because of the site location at the north of the basin, closer to the Uinta mountain range, a diurnal orographic wind pattern of upsloping winds during the daytime, and downslope winds at night are prevalent at this site. Establishing a partial county designation based on a 6,000 feet level is not supported by the data from the 6,216 foot Whiterocks monitor.

In Rio Blanco County, Colorado, along the White River valley, winds under winter temperature inversions are often light and variable. This means that winds speeds are extremely low (often under 1 mph) and sometimes do not show a consistent wind direction from hour to hour. On temperature inversion days when a consistent wind direction is seen, the wind pattern is a downvalley flow (from Colorado towards Utah) during nighttime hours, with a reversal to upvalley winds (from Utah toward Colorado) during daylight and evening hours. The EPA evaluated days in 2013-2016 where the Redwash monitor (the nearest Utah monitor to Rio Blanco County) exceeded the NAAQS. On those exceedance days with directional winds at the Rangely monitor in Rio Blanco County, winds were down-valley toward Utah generally from 1:00 am to about 8:00 am, and then up-valley, from Utah toward Colorado from about 10:00 am until midnight. Average down-valley winds at night were 1.6 mph, while average up-valley winds during the day and evening were 0.8 mph. Net transport for this diurnal pattern (8 hours at 1.6 mph followed by 14 hours in the opposite direction at 0.8 mph) is 1.6 miles of east to west transport per day. The nearest monitor in Utah to Rio Blanco County is the Redwash monitor. Redwash is 16 miles west of Rio Blanco County, and 20 miles west of the oil and gas emission sources in Rio Blanco County. Redwash, however, lacks complete data showing a 2014-2016 NAAQS violation. The nearest violating monitor to Rio Blanco County is the Ouray monitor, 34 miles west of Rio Blanco County, and 40 miles west of the Rio Blanco County emission sources.

Factor 4: Geography/topography

Consideration of geography or topography can provide additional information relevant to defining nonattainment area boundaries. Analyses should examine the physical features of the land that might define the airshed. Mountains or other physical features may influence the fate and transport of emissions as well as the formation and distribution of ozone concentrations. The absence of any such geographic or topographic features may also be a relevant consideration in selecting boundaries for a given area.

The EPA used geography/topography analysis to evaluate the physical features of the land that might affect the airshed and, therefore, the distribution of ozone over the area. Figure 22 shows the region of northern Utah which includes the Uinta Basin (primarily in Uintah and Duchesne Counties) and the small portion of the basin in western Rio Blanco County, Colorado. Figure 23, from the Utah designation recommendation[24] more clearly shows the topography of the basin and the physical features surrounding it. The Uinta Basin is entirely enclosed by higher level terrain on all sides which prevents transport of emissions into the basin from surrounding counties. The only low elevation breaks in the surrounding higher terrain are the incoming Green and White River Valleys (entering the basin at elevations of 4,800 and 5,600 feet, respectively) and the outlet to the south along the Green River (at 4,625 feet). Under wintertime temperature inversion conditions, cold air pools at the lower elevations in the basin, and pollutants are trapped in the pooled air under the temperature inversion. As long as snow cover is present, inversions can persist for periods longer than a week, until energetic weather systems break the temperature inversion and sweep out trapped pollutants. While trapping locally emitted pollutants under an inversion layer within the basin, the inversion

[24] UT TSD, p. 50.

layer also prevents transported pollutants from outside the basin from entering the basin and contributing to ozone formation, as warmer air aloft carrying upwind emissions tends to float across the colder air trapped below. As long as a temperature inversion is present, resulting in the coldest air lying at or near the surface, and with warmer air above the inversion, transported pollutants arriving aloft at higher temperatures than the surface are prevented from descending through the inversion layer and impacting the local photochemistry.

Figure 22. Topographic Illustration of the Physical Features

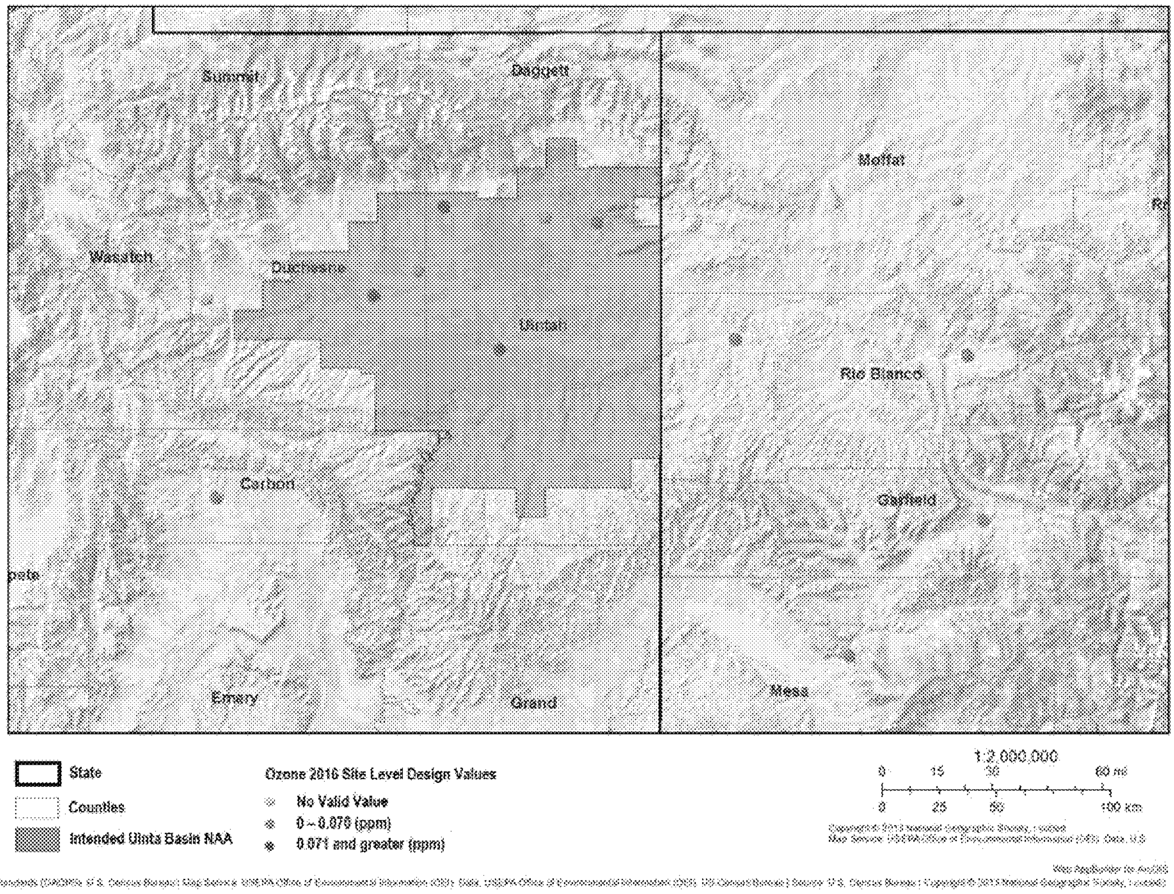
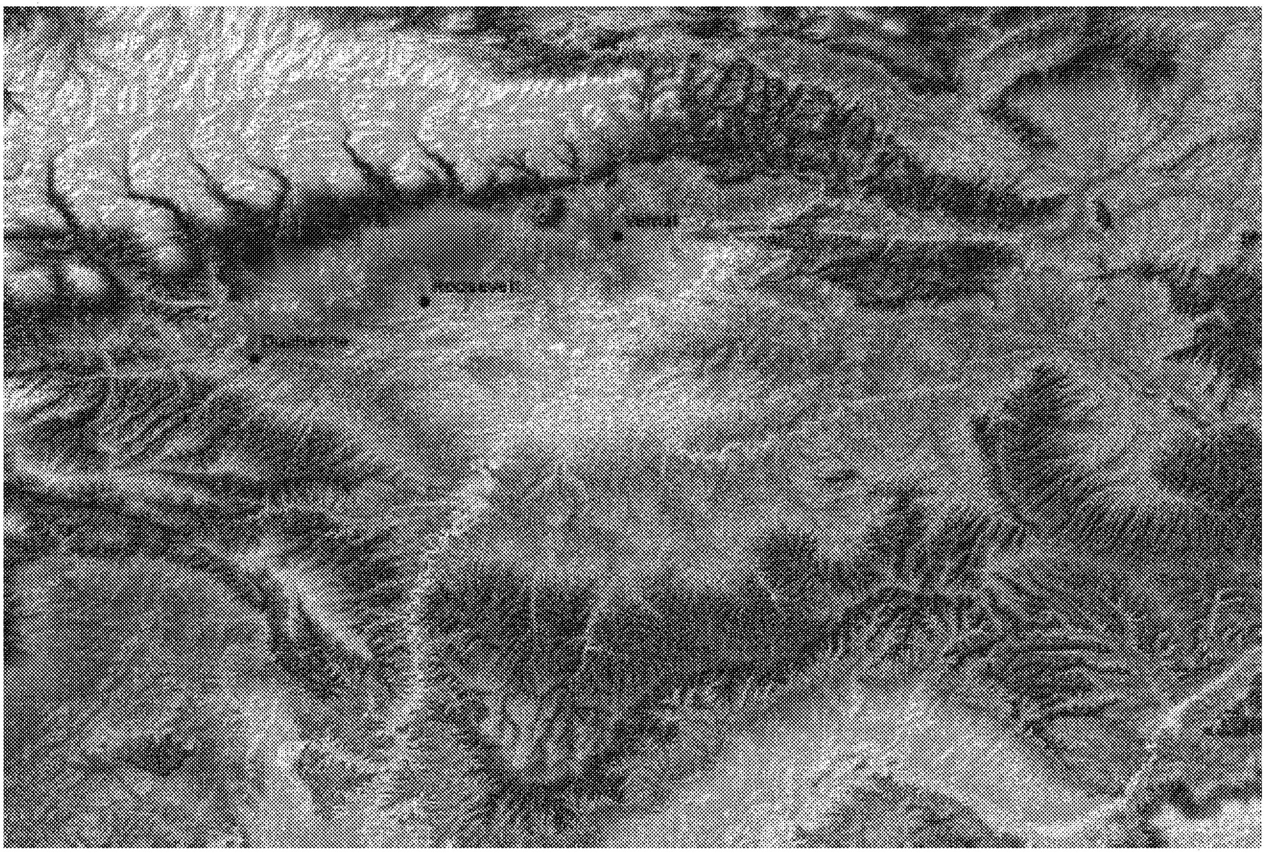


Figure 23. Topography of the Uinta Basin of Utah.



Factor 5: Jurisdictional boundaries

Once the geographic extent of the violating area and the nearby area contributing to violations is determined, the EPA considered existing jurisdictional boundaries for the purposes of providing a clearly defined legal boundary to carry out the air quality planning and enforcement functions for nonattainment areas. In defining the boundaries of the intended Uinta Basin nonattainment area, the EPA considered existing jurisdictional boundaries, which can provide easily identifiable and recognized boundaries for purposes of implementing the NAAQS. Examples of jurisdictional boundaries include, but are not limited to: states, counties, air districts, areas of Indian country, metropolitan planning organizations, and existing nonattainment areas. If an existing jurisdictional boundary is used to help define the nonattainment area, it must encompass all of the area that has been identified as meeting the nonattainment definition. Where existing jurisdictional boundaries are not adequate or appropriate to describe the nonattainment area, the EPA considered other clearly defined and permanent landmarks or geographic coordinates for purposes of identifying the boundaries of the intended designated areas.

The EPA evaluated the existing county jurisdictional boundaries in determining an appropriate nonattainment boundary for the Uinta Basin. For Uintah County, oil and gas development is prevalent throughout the county with the exception of the mountainous northern portion, and those sources contribute to violating monitors. For Duchesne County, significant oil and gas development has occurred in the eastern and southern portion of the county. However, much of the county to the west of the town of Duchesne does not have any oil and gas development or other sources of ozone precursors emissions that could contribute to violating monitors in the Uinta Basin. As noted earlier, for both Uintah and Duchesne Counties, the northern portions of the counties are undeveloped and include large areas of U. S. Forest Service land. For Rio Blanco County, emission sources lie within the Uinta Basin portion of the county, but are remote from violating monitors.

The Uinta Basin also includes portions of Indian country. As defined at 18 U.S.C. 1151, "Indian country" refers to: "(a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same." The EPA recognizes the sovereignty of tribal governments, and has attempted to take the input of the tribes into account in establishing appropriate nonattainment area boundaries.

As noted earlier, the Ute Indian Tribe provided the EPA with a recommendation of attainment for the entire tribal area within the Uinta Basin – assuming the EPA concurs on an exceptional events demonstration for two days in June 2015. If the EPA disagrees with the exceptional event package, the Ute Tribe requests that an unspecified area around the Ouray monitor be designated nonattainment. Regardless of whether there was an exceptional event on the two days in June 2015, the 2014-2016 monitoring data still shows violations at three tribal monitors within the basin. The Clean Air Act requires that any area containing a violating monitor must be designated nonattainment. The majority (80 percent) of oil and gas sources in the Uinta Basin are located on tribal land. As discussed earlier, when inversions occur and air is uniformly mixed below the inversion, sources throughout the basin contribute to violations at both state and tribal monitors.

Conclusion for Uinta Basin

The EPA intends to designate portions of Duchesne and Uintah Counties, including both state and tribal lands located in those portions of the county, as nonattainment for the 2015 ozone standard. The EPA intends to modify the State's recommendation that the boundary for the nonattainment area be established at an elevation of 6,000 feet. The EPA also intends to modify the recommendation provided by the Ute Tribe – specifically, the recommendation to designate an area of nonattainment only surrounding the Ouray monitor. Two other monitors at Whiterocks (Uintah County) and Myton (Duchesne County) are also measuring violations of the NAAQS and the tribe's recommended boundary would not include those violating monitors. VOC emissions from oil and gas sources are the primary contributors to elevated ozone in the Uinta Basin. As discussed in the five-factor analysis, these precursor emissions originate from oil and gas operations on both state and tribal land. Additionally, The EPA finds that designating townships below 6,000 feet, as proposed by Utah, does not sufficiently include all violating monitors and contributing sources. The Whiterocks regulatory monitor is measuring a 2016 design value in violation of the 2015 ozone NAAQS and is located at 6,216 ft. Subsequently, the EPA concludes that areas above 6,000 ft. are violating the NAAQS, and sources above 6,000 ft are contributing to the formation of ozone in excess of the NAAQS. Based on Clean Air Act requirements, nonattainment boundaries must be defined to adequately capture all violating monitors. The EPA intends to modify the State's recommendation to include all townships below 6,250 ft to ensure that the Whiterocks monitor is included in the nonattainment boundary. The EPA's intended boundary would include 93 percent[25] of all oil and natural gas wells and 92 percent[26] of all oil and natural gas emissions, as well as most major sources and populated areas. Consistent with Utah's methodology, the EPA intends to include all townships with greater than 10 percent of land below 6,250 ft in the nonattainment area. A list of the affected townships is presented in Table 12.

Table 12. List of Townships Included in the Uinta Basin Nonattainment Area.

Duchesne County - Salt Lake Meridian
Township 8 South Range 15 East
Township 8 South Range 16 East
Township 8 South Range 17 East
Township 9 South Range 15 East
Township 9 South Range 16 East
Township 9 South Range 17 East
Township 10 South Range 16 East
Township 10 South Range 17 East
Township 11 South Range 16 East
Township 11 South Range 17 East
Township 12 South Range 17 East
Duchesne County - Uintah Meridian
Township 1 North Range 1 West
Township 1 North Range 2 West
Township 1 South Range 1 West
Township 1 South Range 2 West
Township 1 South Range 3 West
Township 2 South Range 1 West
Township 2 South Range 2 West
Township 2 South Range 3 West
Township 2 South Range 4 West
Township 2 South Range 5 West
Township 3 South Range 1 West
Township 3 South Range 2 West
Township 3 South Range 3 West
Township 3 South Range 4 West
Township 3 South Range 5 West
Township 3 South Range 6 West
Township 4 South Range 1 West

[25] Based on wells included in the EPA's intended boundary compared with all wells in Uintah and Duchesne Counties. The well locations were obtained from the Utah Department of Oil, Gas, and Mining

[26] Emissions information was obtained from the 2014 Uinta Basin Emissions Inventory for all sources located below 6,250 ft.

Township 4 South Range 2 West
Township 4 South Range 3 West
Township 4 South Range 4 West
Township 4 South Range 5 West
Township 4 South Range 6 West
Township 4 South Range 7 West
Township 5 South Range 3 West
Township 5 South Range 4 West
Uintah County - Salt Lake Meridian
Township 2 South Range 22 East
Township 3 South Range 21 East
Township 3 South Range 22 East
Township 3 South Range 23 East
Township 3 South Range 24 East
Township 3 South Range 25 East
Township 4 South Range 19 East
Township 4 South Range 20 East
Township 4 South Range 21 East
Township 4 South Range 22 East
Township 4 South Range 23 East
Township 4 South Range 24 East
Township 5 South Range 19 East
Township 5 South Range 20 East
Township 5 South Range 21 East
Township 5 South Range 22 East
Township 5 South Range 23 East
Township 5 South Range 24 East
Township 5 South Range 25 East
Township 6 South Range 19 East
Township 6 South Range 20 East
Township 6 South Range 21 East
Township 6 South Range 22 East
Township 6 South Range 23 East
Township 6 South Range 24 East
Township 6 South Range 25 East
Township 7 South Range 19 East
Township 7 South Range 20 East
Township 7 South Range 21 East
Township 7 South Range 22 East
Township 7 South Range 23 East
Township 7 South Range 24 East

Township 7 South Range 25 East
Township 8 South Range 17 East
Township 8 South Range 18 East
Township 8 South Range 19 East
Township 8 South Range 20 East
Township 8 South Range 21 East
Township 8 South Range 22 East
Township 8 South Range 23 East
Township 8 South Range 24 East
Township 8 South Range 25 East
Township 9 South Range 17 East
Township 9 South Range 18 East
Township 9 South Range 19 East
Township 9 South Range 20 East
Township 9 South Range 21 East
Township 9 South Range 22 East
Township 9 South Range 23 East
Township 9 South Range 24 East
Township 9 South Range 25 East
Township 10 South Range 17 East
Township 10 South Range 18 East
Township 10 South Range 19 East
Township 10 South Range 20 East
Township 10 South Range 21 East
Township 10 South Range 22 East
Township 10 South Range 23 East
Township 10 South Range 24 East
Township 10 South Range 25 East
Township 11 South Range 17 East
Township 11 South Range 18 East
Township 11 South Range 19 East
Township 11 South Range 20 East
Township 11 South Range 21 East
Township 11 South Range 22 East
Township 11 South Range 23 East
Township 11 South Range 24 East
Township 11 South Range 25 East
Township 12 South Range 17 East
Township 12 South Range 18 East
Township 12 South Range 19 East
Township 12 South Range 20 East
Township 12 South Range 21 East

Township 12 South Range 22 East
Township 12 South Range 23 East
Township 12 South Range 24 East
Township 12 South Range 25 East
Township 13 South Range 17 East
Township 13 South Range 18 East
Township 13 South Range 19 East
Township 13 South Range 20 East
Township 13 South Range 21 East
Township 13 South Range 22 East
Township 13 South Range 23 East
Township 13 South Range 24 East
Township 14 South Range 17 East
Township 14 South Range 21 East
Township 15 South Range 17 East
Township 16 South Range 17 East
Uintah County - Uintah Meridian
Township 1 North Range 1 East
Township 1 North Range 1 West
Township 1 North Range 2 East
Township 1 South Range 1 East
Township 1 South Range 1 West
Township 1 South Range 2 East
Township 2 South Range 1 East
Township 2 South Range 1 West
Township 2 South Range 2 East
Township 3 South Range 1 East
Township 3 South Range 1 West
Township 3 South Range 2 East
Township 4 South Range 1 East
Township 4 South Range 1 West
Township 4 South Range 2 East
Township 4 South Range 3 East
Township 5 South Range 1 East
Township 5 South Range 2 East
Township 5 South Range 3 East

Although a portion of Rio Blanco County is within the Uinta Basin, the EPA does not intend to include it in the nonattainment area and intends to designate all of Rio Blanco County as attainment/unclassifiable for the 2015 ozone NAAQS. As provided above, the emissions in Rio Blanco County are small in comparison to the emissions from oil and gas operations in the two Utah Counties and on tribal land, and it is those emissions that are driving the unique wintertime ozone violations in area. In addition, Rio Blanco County emissions sources are located far from violating monitors, and the extremely low transport wind speeds recorded in Rangely, Colorado, show insufficient transport to violating monitors to allow these emissions to contribute to violations.

The EPA concludes that designating a boundary that includes portions of Duchesne and Uintah Counties in townships below 6,250 ft will support Utah and the Ute Tribe's ability to focus resources on the emission sources and areas that most strongly contribute to the ozone problem in the Uinta Basin.

Air Toxics

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-1162-17

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: December 19, 2017

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – November 2017

Asbestos Demolition/Renovation NESHAP Inspections	36
Asbestos AHERA Inspections	6
Asbestos State Rules Only Inspections	12
Asbestos Notification Forms Accepted	137
Asbestos Telephone Calls Answered	215
Asbestos Individuals Certifications Approved/Disapproved	59/0
Asbestos Company Certifications/Re-Certifications	0/8
Asbestos Alternate Work Practices Approved/Disapproved	5/0
Lead-Based Paint (LBP) Inspections	0
LBP Notification Forms Approved	1
LBP Telephone Calls Answered	2
LBP Letters Prepared and Mailed	6
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	0
LBP Individual Certifications Approved/Disapproved	15/0
LBP Firm Certifications	8

Notices of Violation Sent	0
Compliance Advisories Sent	17
Warning Letters Sent	16
Settlement Agreements Finalized	4
Penalties Agreed to:	
CertaPro Painters of West Salt Lake City	$ 1,300.00
Grant Mackay Demolition Company	$ 1,575.00
Environmental Solutions	$ 1,500.00
All States Mechanical, LLC	$ 1,500.00
	$ 5,875.00

Compliance

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-1713-17

MEMORANDUM

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: December 20, 2017

SUBJECT: Compliance Activities – November 2017

Annual Inspections Conducted:

Major 7
Synthetic Minor 2
Minor 19

On-Site Stack Test Audits Conducted: 4

Stack Test Report Reviews: 51

On-Site CEM Audits Conducted: 0

Emission Reports Reviewed: 0

Temporary Relocation Requests Reviewed & Approved: 0

Fugitive Dust Control Plans Reviewed & Accepted: 91

Open Burn Permits Issued: 0

Soil Remediation Report Reviews: 0

[1]Miscellaneous Inspections Conducted: 9

Complaints Received: 2

195 North 1950 West • Salt Lake City, Utah
Mailing Address: P.O. Box 144820 • Salt Lake City, Utah 84114-4820
Telephone (801) 536-4000 • Fax (801)536-4099 • T.D.D. (801) 903-3978
www.deq.utah.gov

Breakdown Reports Received:..2

Compliance Actions Resulting From a Breakdown..0

Warning Letters Issued: 5

Notices of Violation Issued:...2

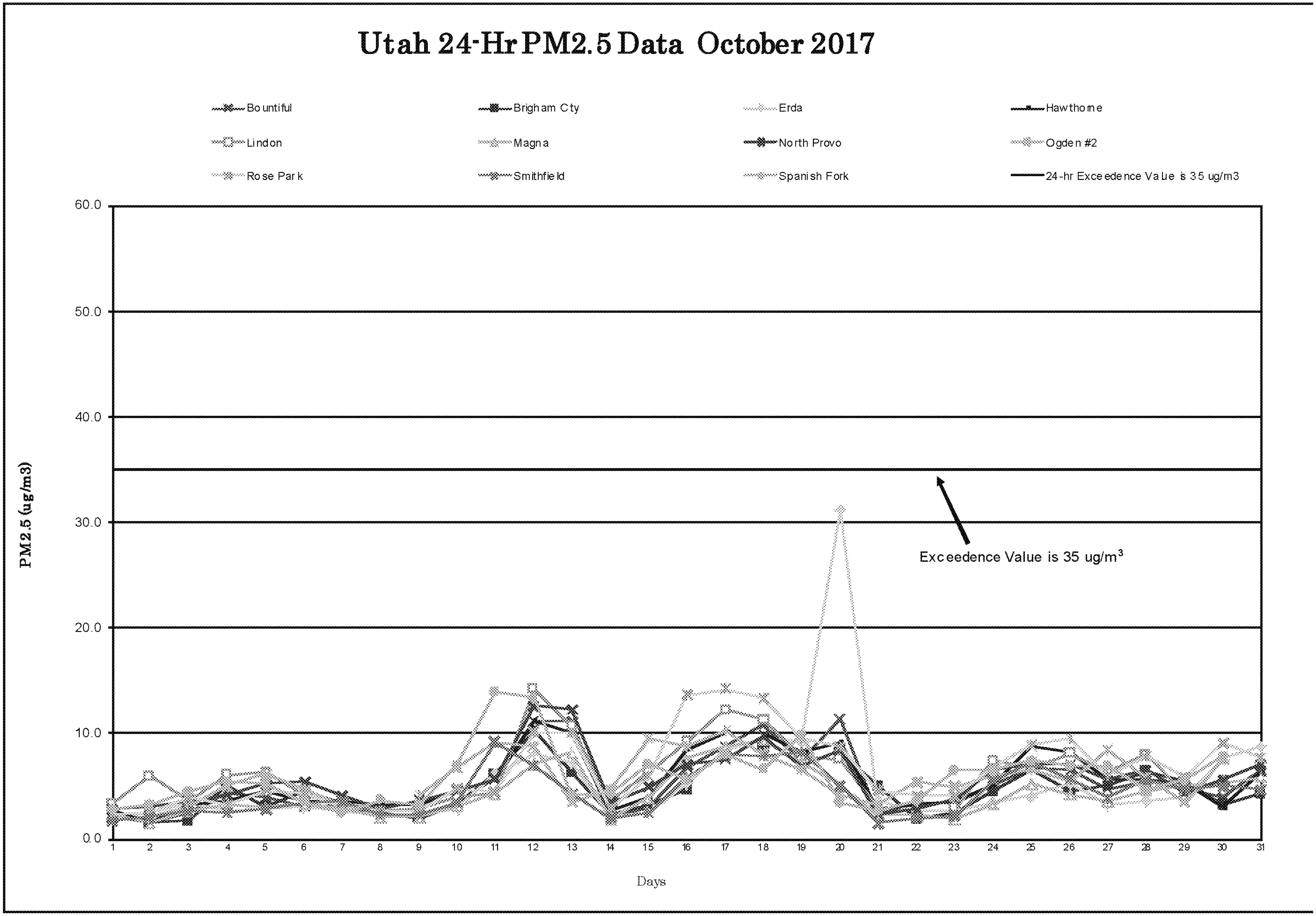
Compliance Advisories Issued:...2

Settlement Agreements Reached: 1

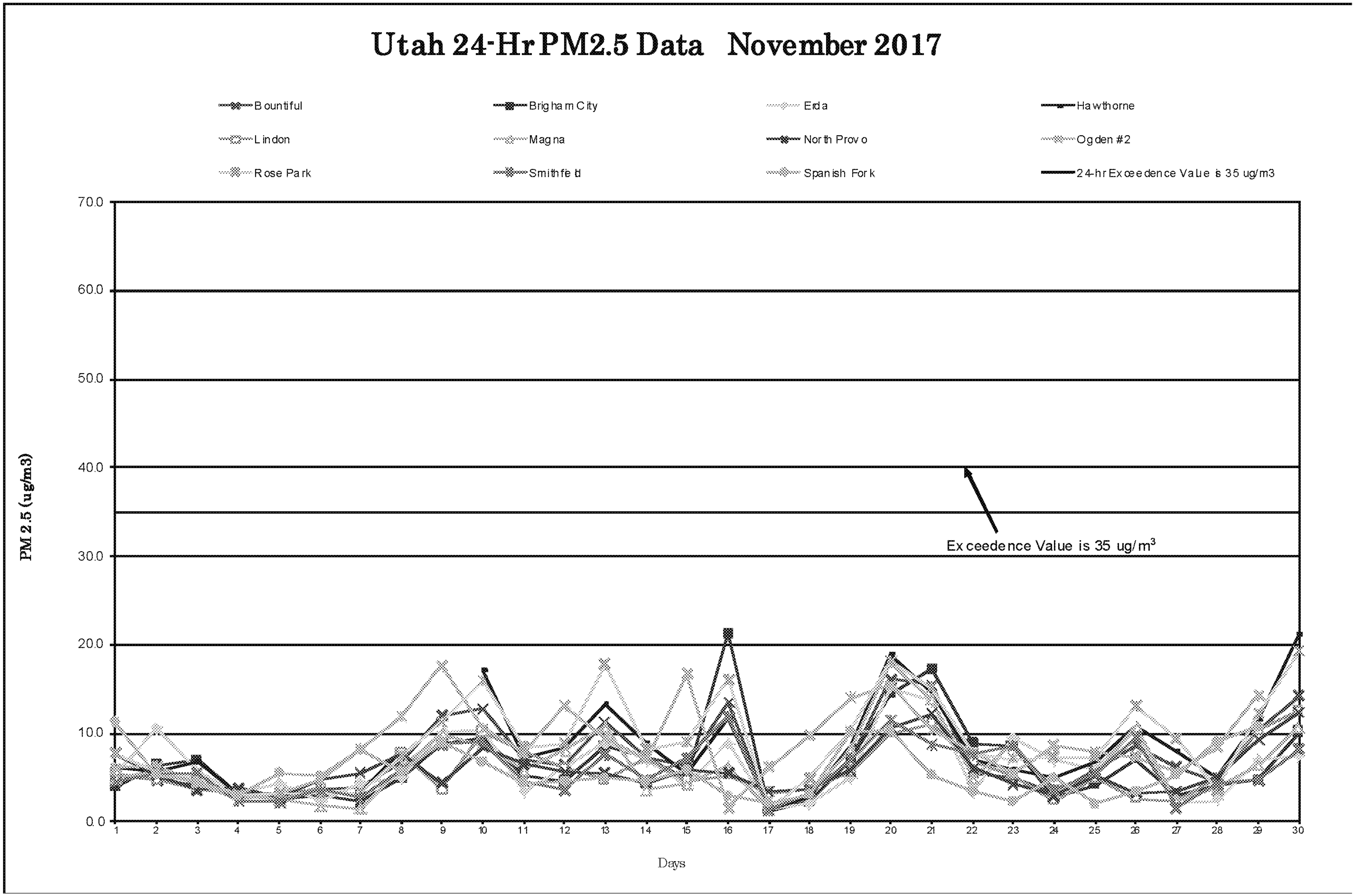
Kaycee Simpson $299.00

[1]Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.

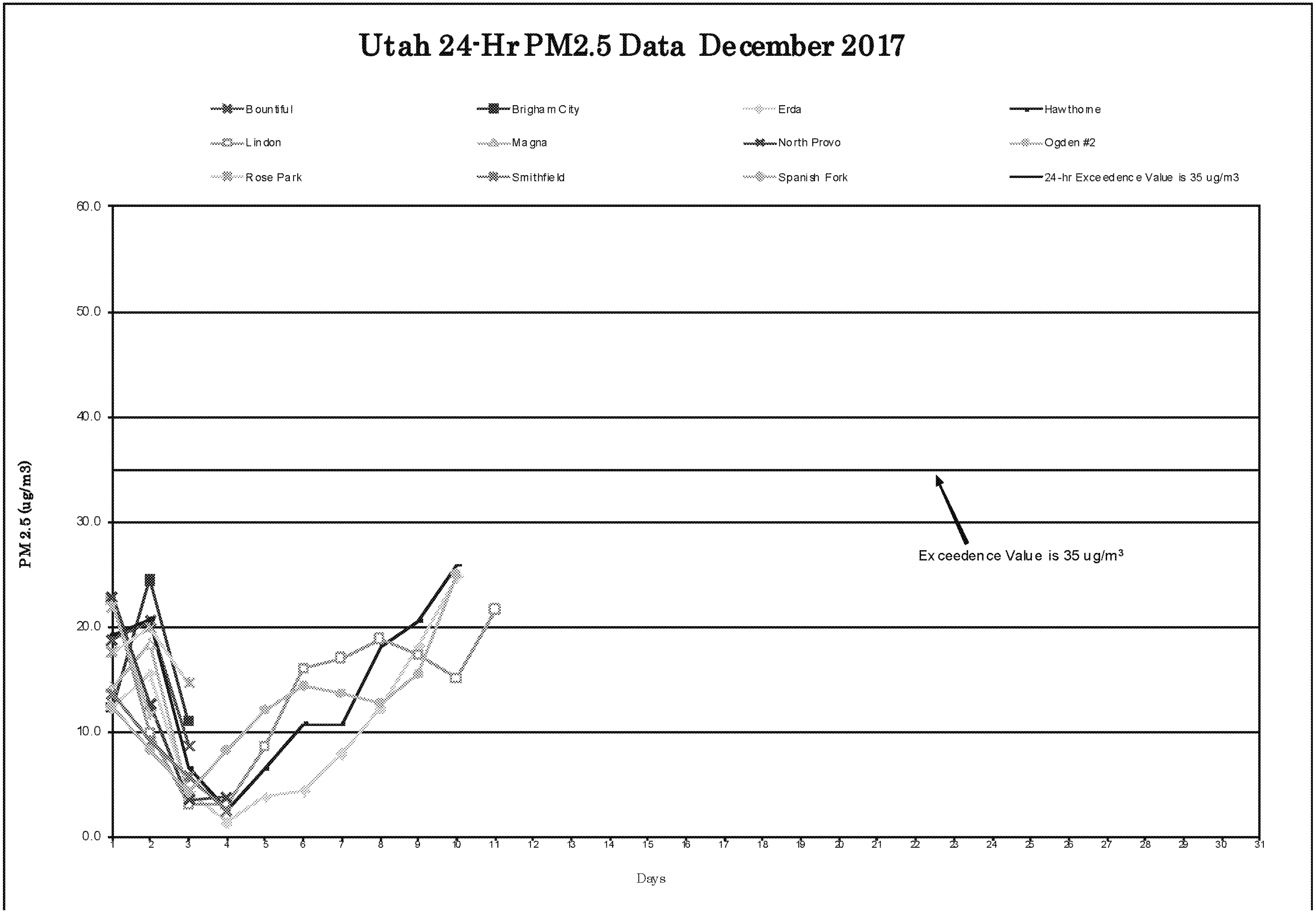
Air Monitoring



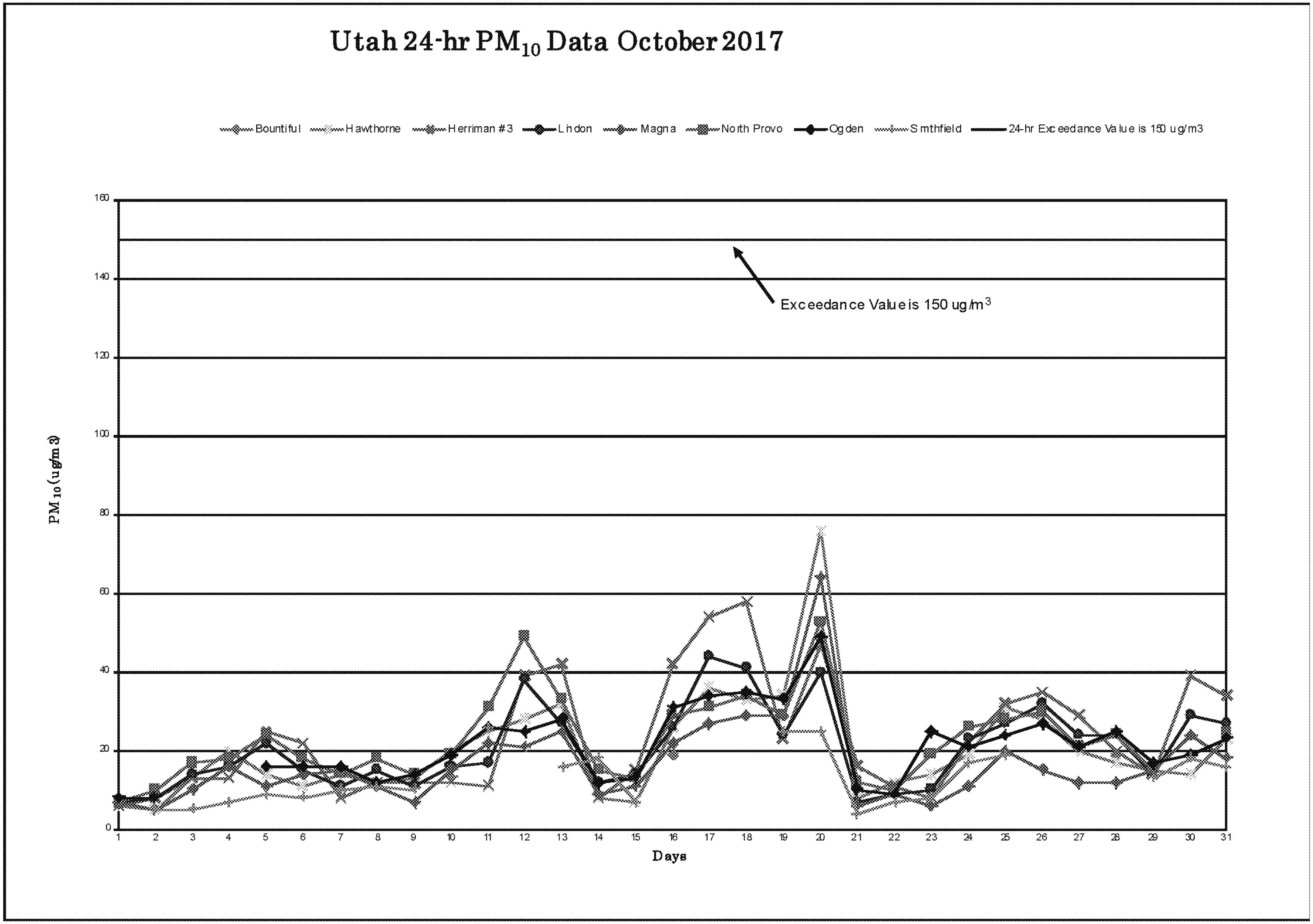
Utah Division of Air Quality



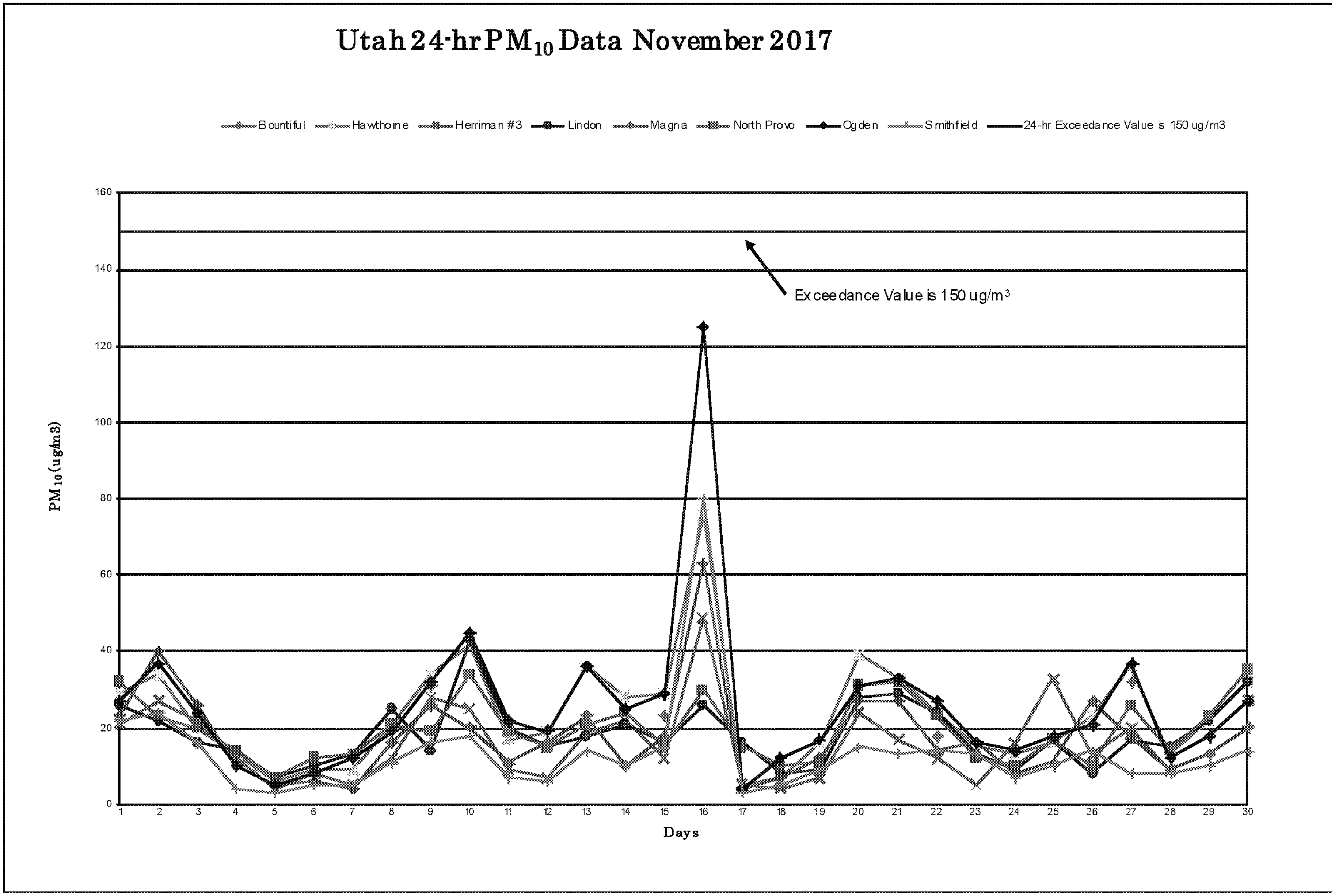
Utah Division of Air Quality



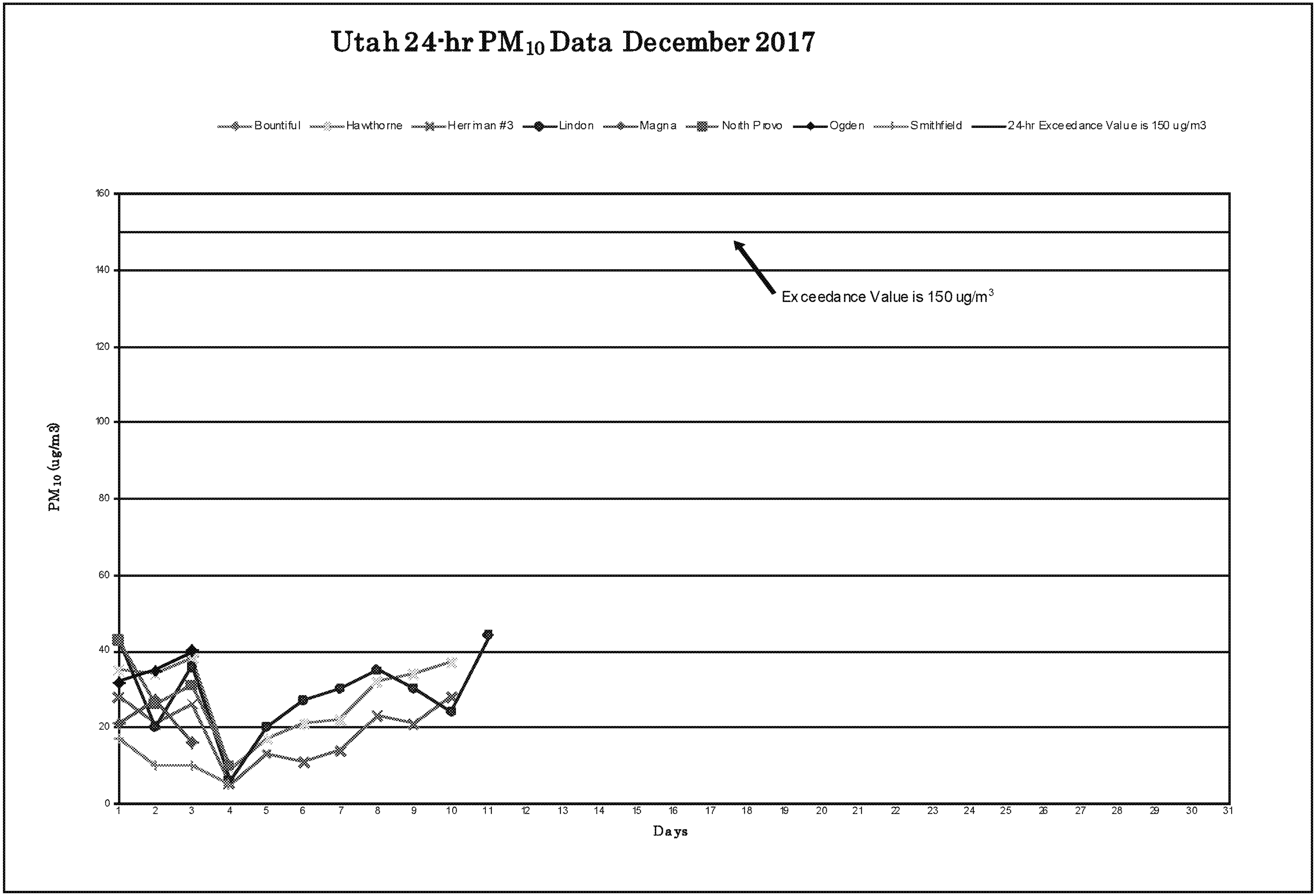
Utah Division of Air Quality



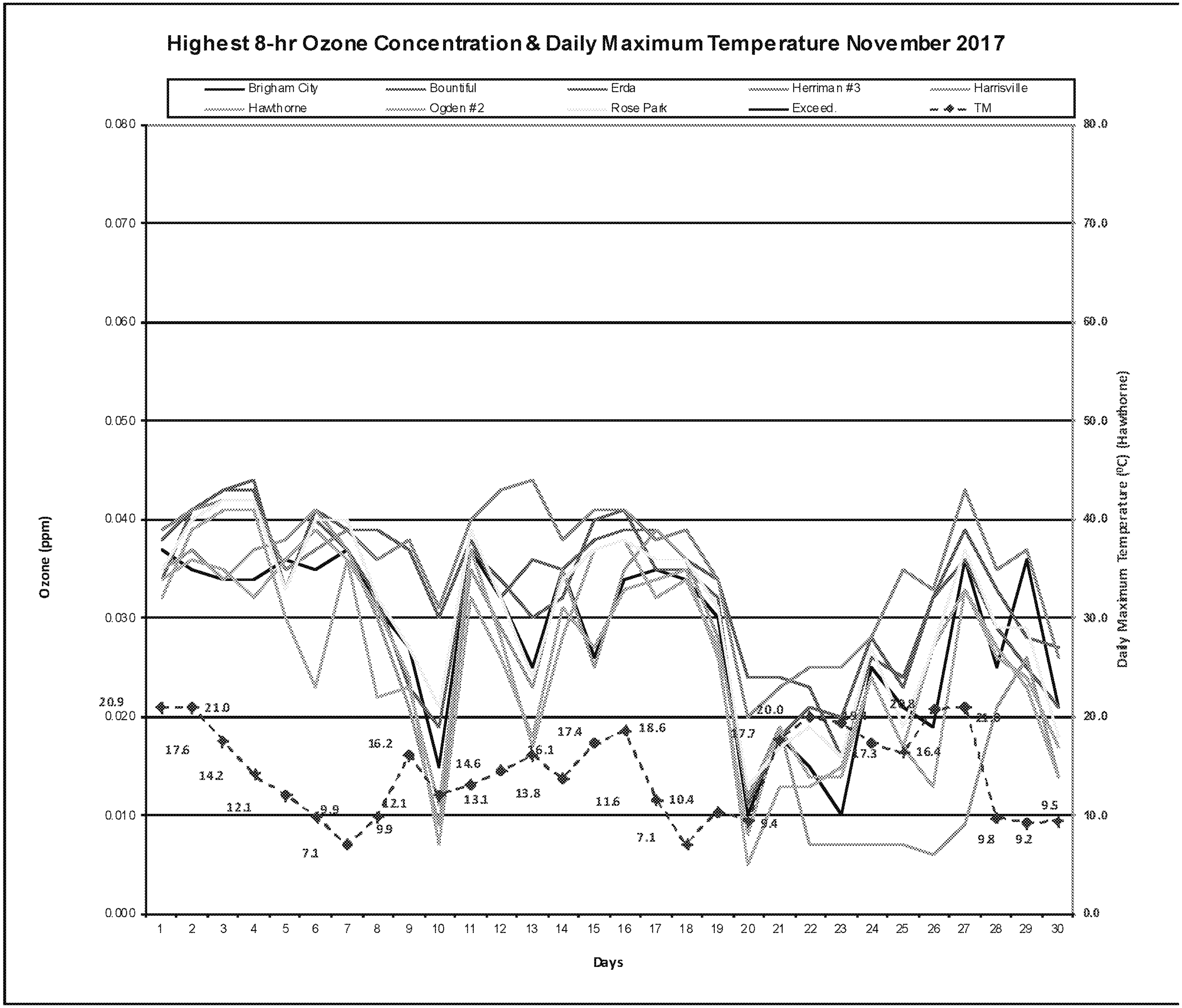
Utah Division of Air Quality

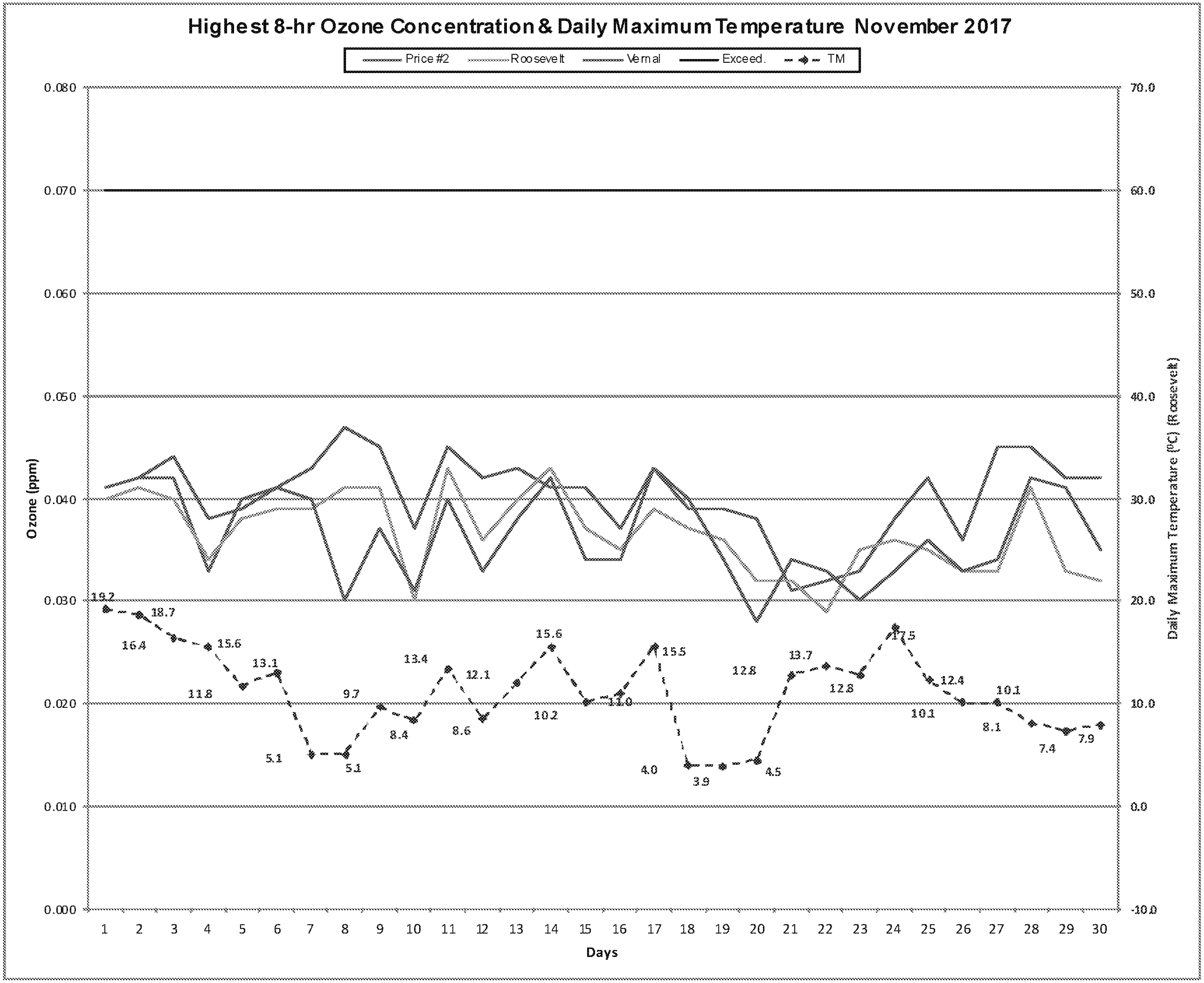


Utah Division of Air Quality

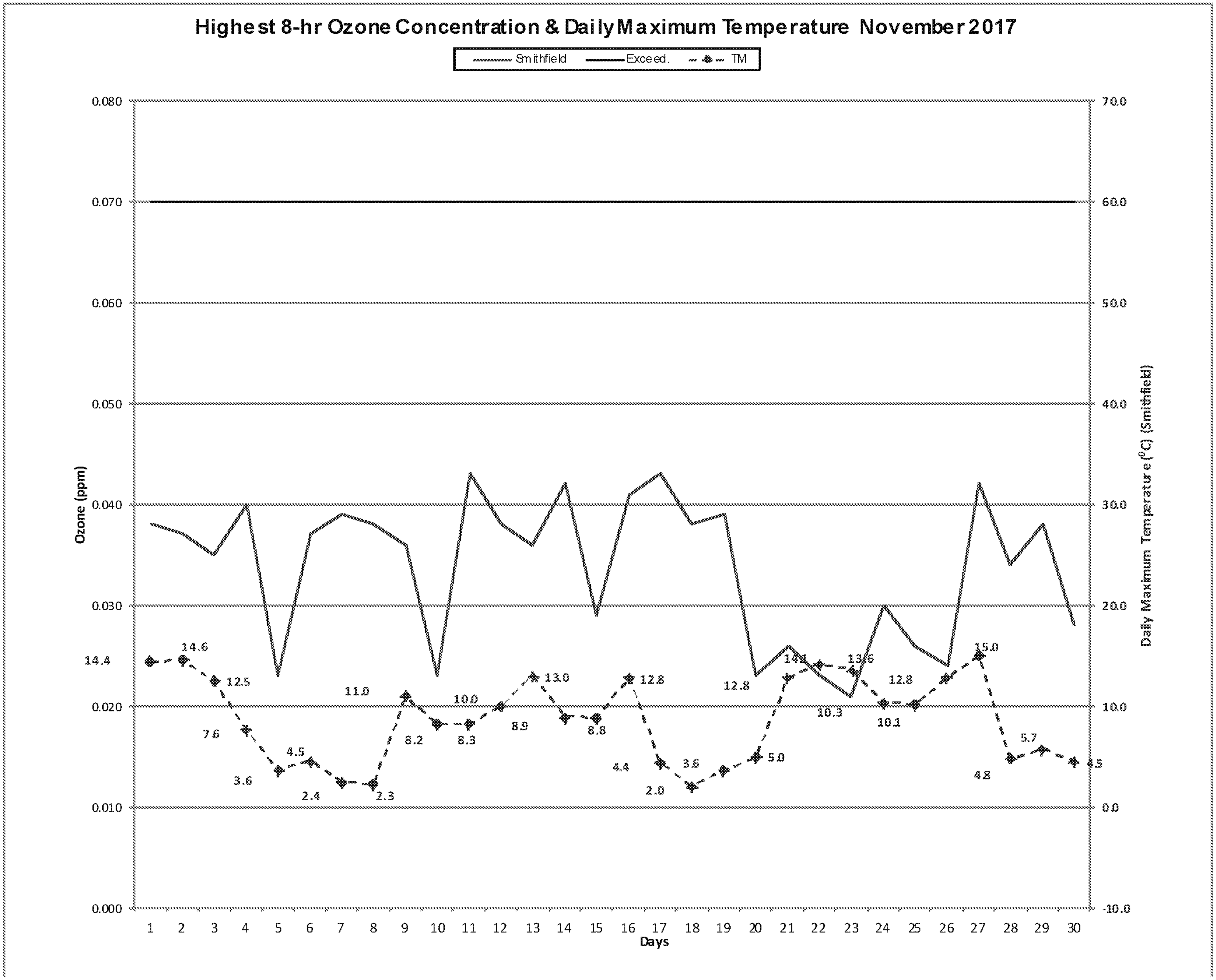


Utah Division of Air Quality


Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2017
Brigham City
Bountiful
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Rose Park
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hawthorne)
Days
0.000
0.010
0.020
0.030
0.040
0.050
0.060
0.070
0.080
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30



Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2017
Price #2
Roosevelt
Vernal
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Roosevelt)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
19.2
18.7
16.4
15.6
11.8
13.1
5.1
5.1
9.7
8.4
13.4
8.6
12.1
10.2
15.6
11.0
15.5
4.0
3.9
12.8
4.5
13.7
12.8
17.5
12.4
10.1
10.1
8.1
7.4
7.9



Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2017
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Smithfield)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
14.4
14.6
12.5
7.6
3.6
4.5
2.4
2.3
11.0
8.2
10.0
8.3
8.9
13.0
8.8
12.8
4.4
2.0
3.6
5.0
12.8
10.3
13.6
12.8
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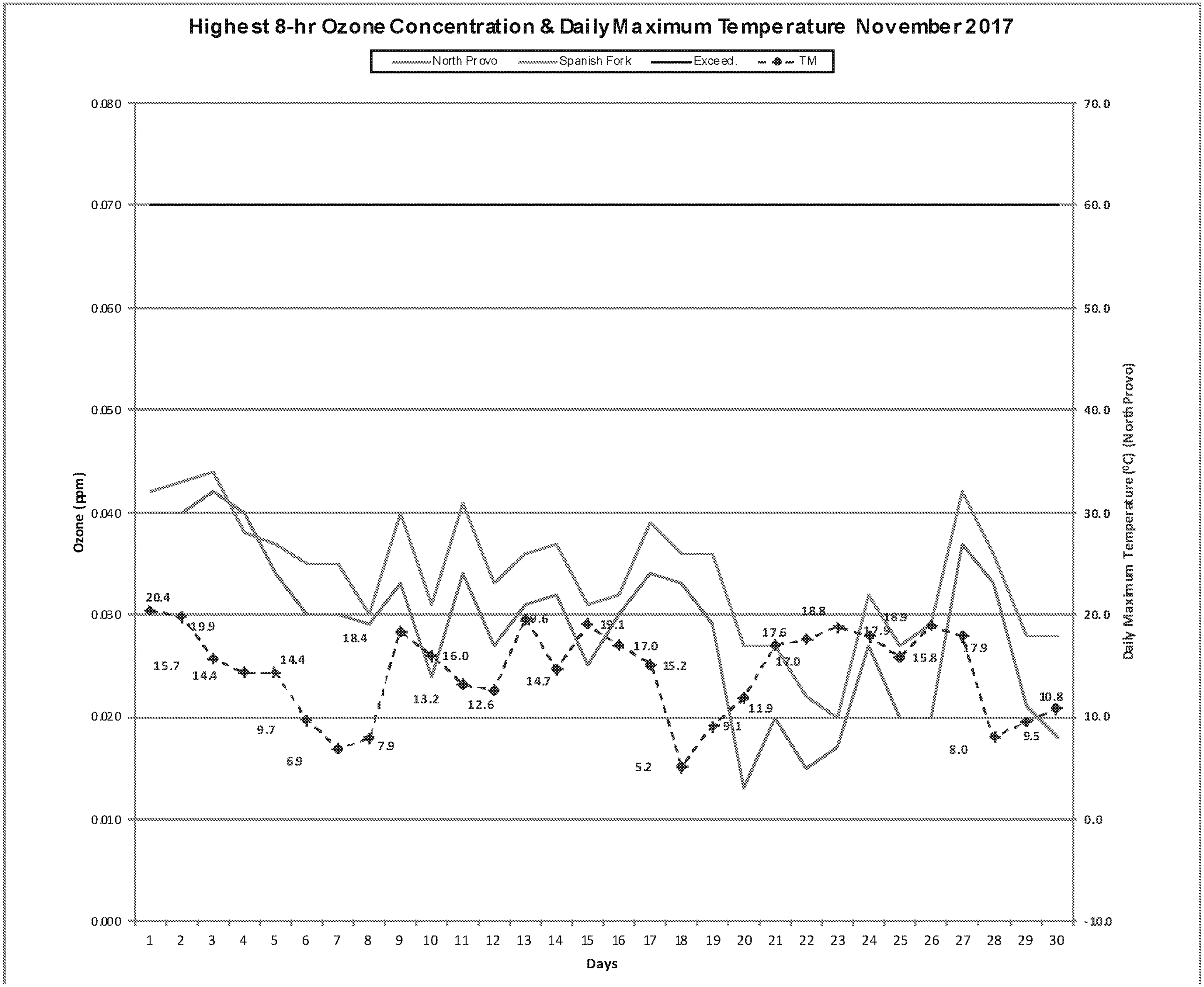
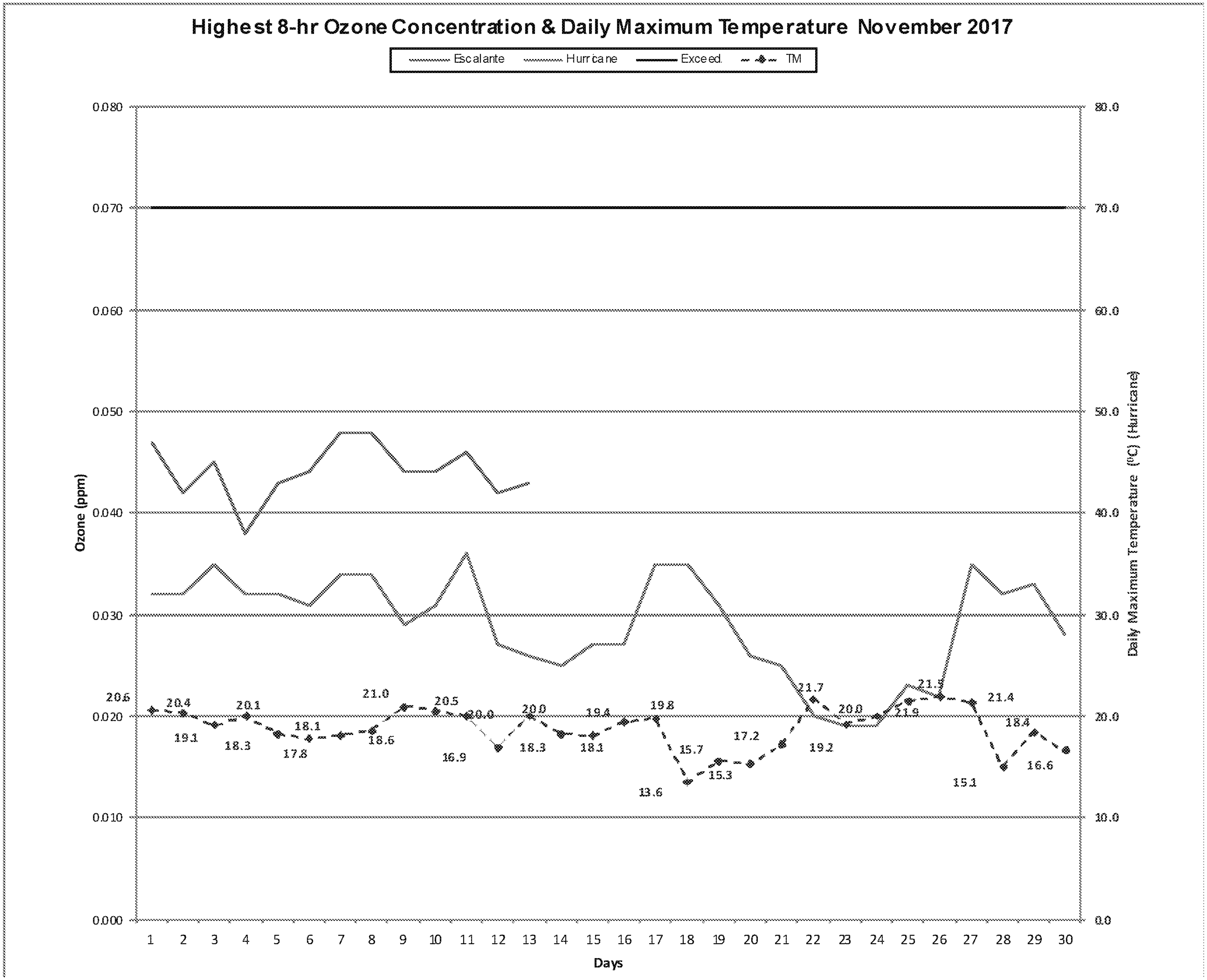
4.8
5.7
4.5



Highest 8-hr Ozone Concentration & Daily Maximum Temperature November 2017
North Provo
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (North Provo)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
20.4
19.9
15.7
14.4
14.4
9.7
6.9
7.9
18.4
16.0
13.2
12.6
14.7
17.0
15.2
5.2
11.9
17.6
17.0
18.8
17.9
18.9
15.8
17.9
8.0
9.5
10.8



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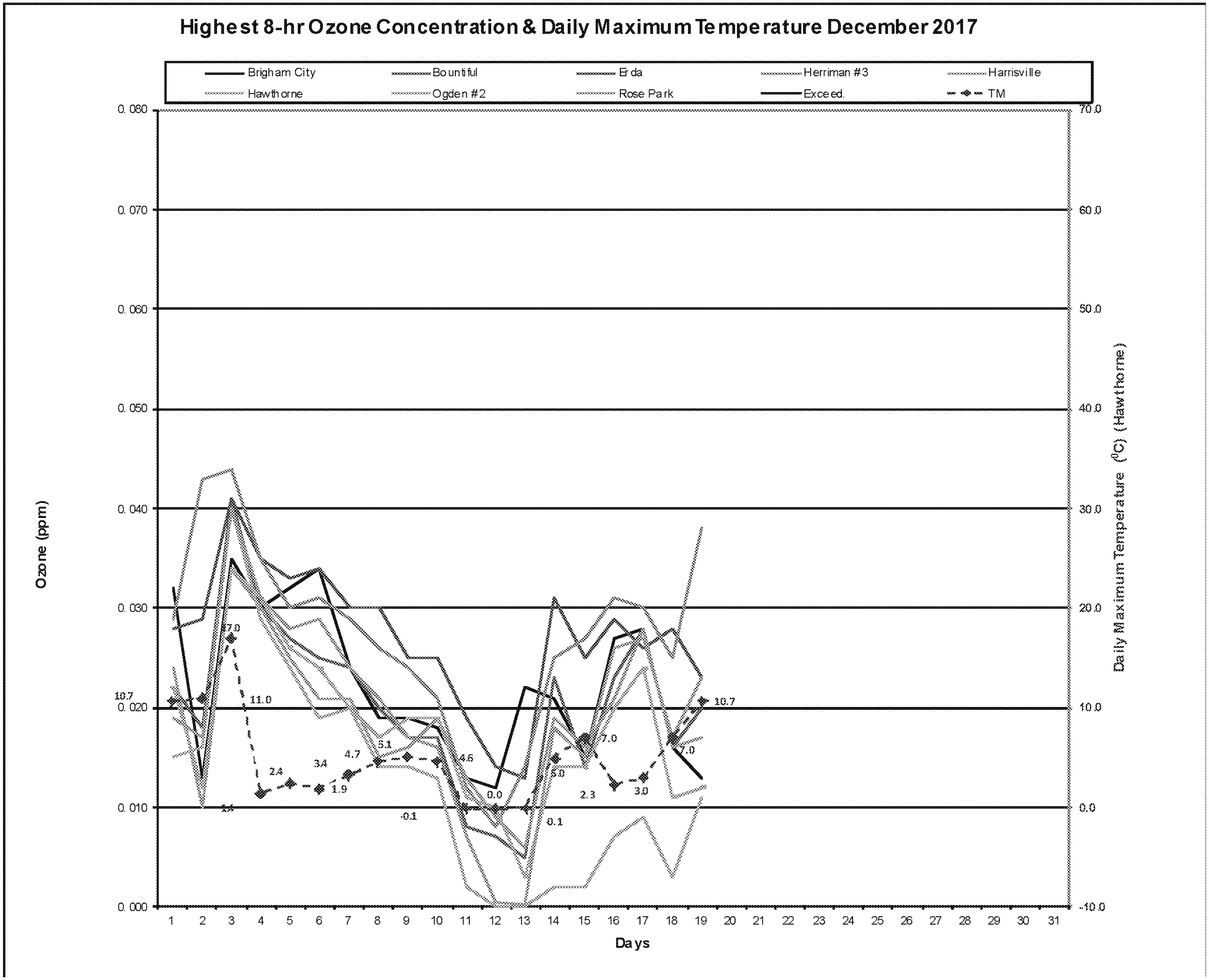
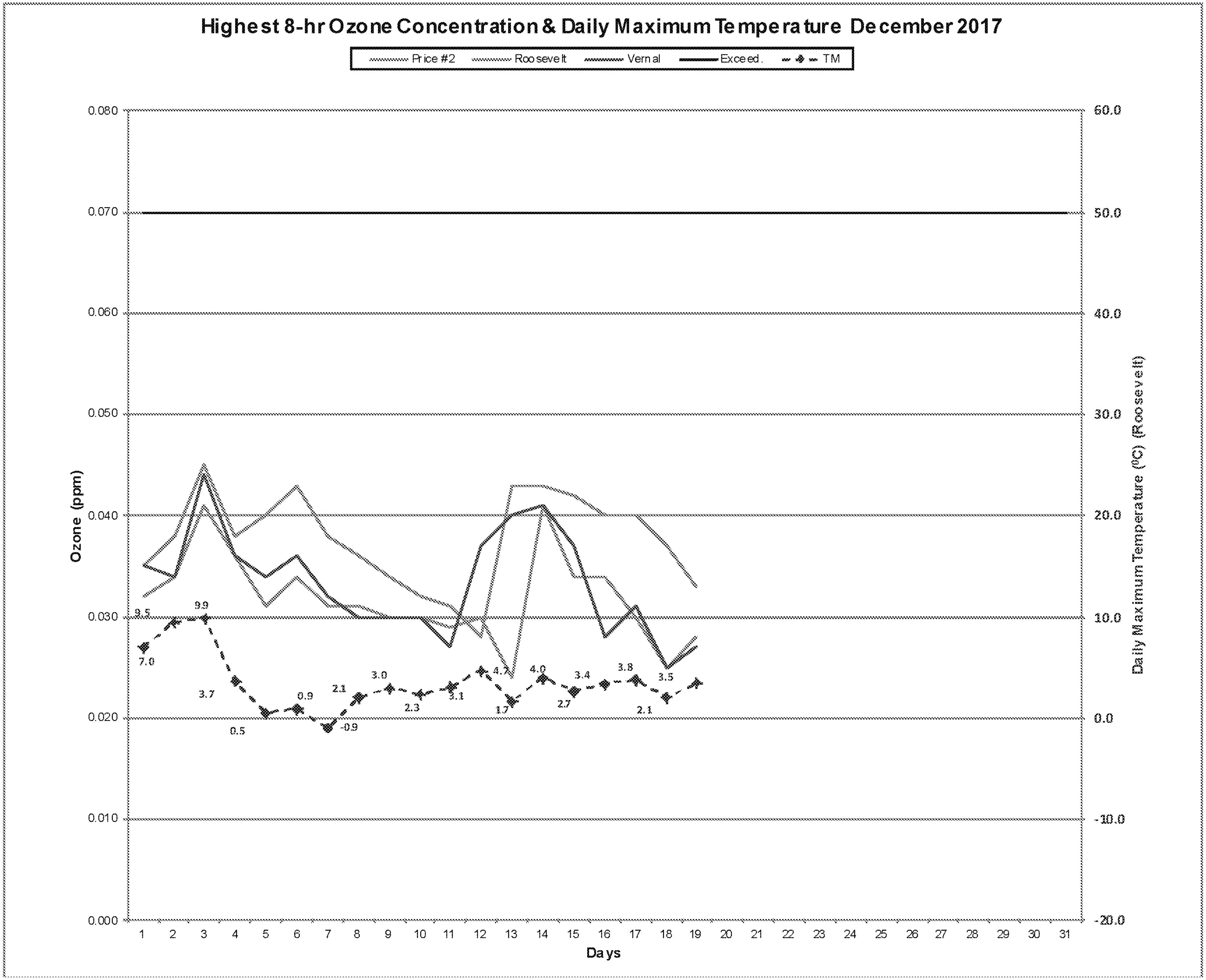
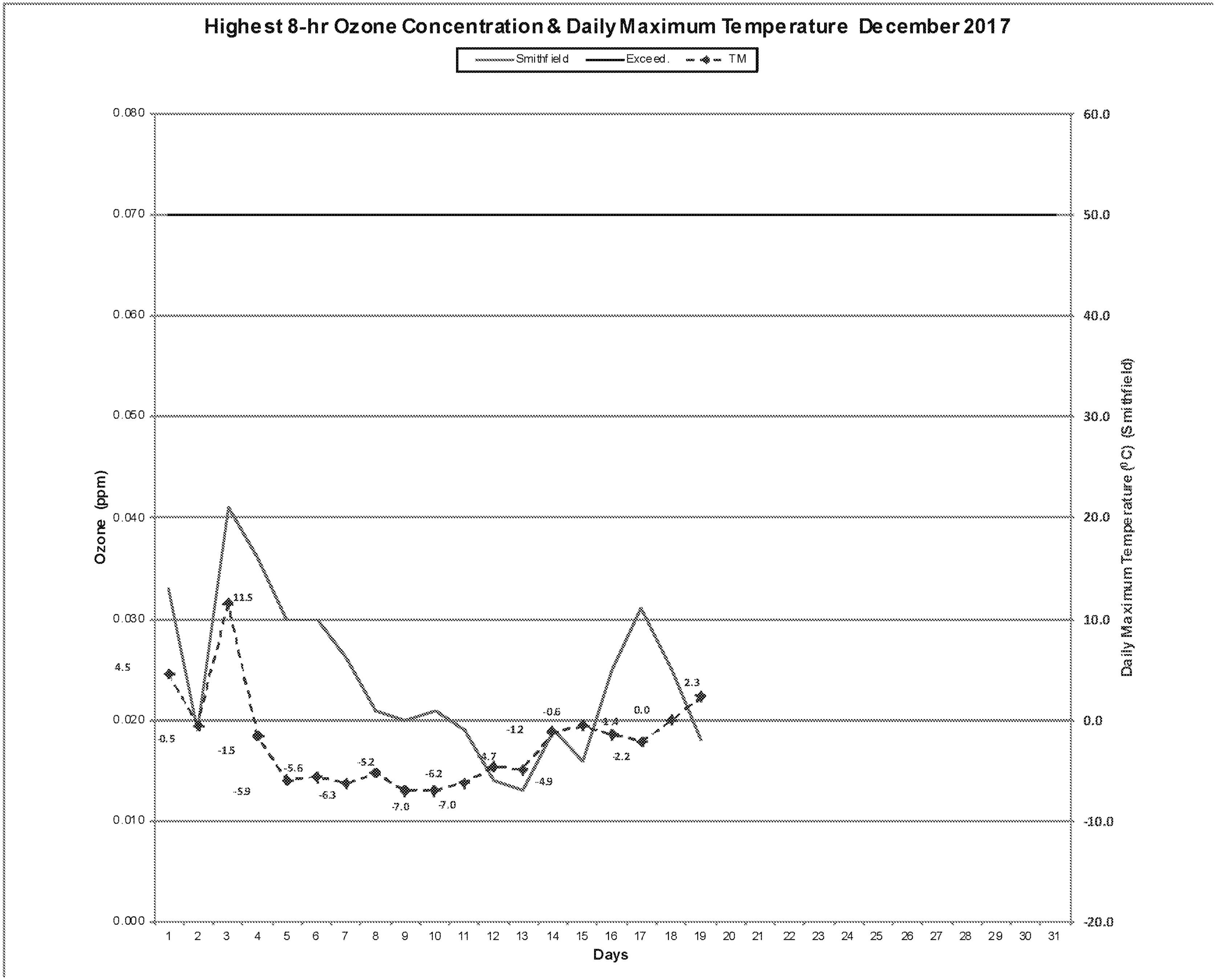
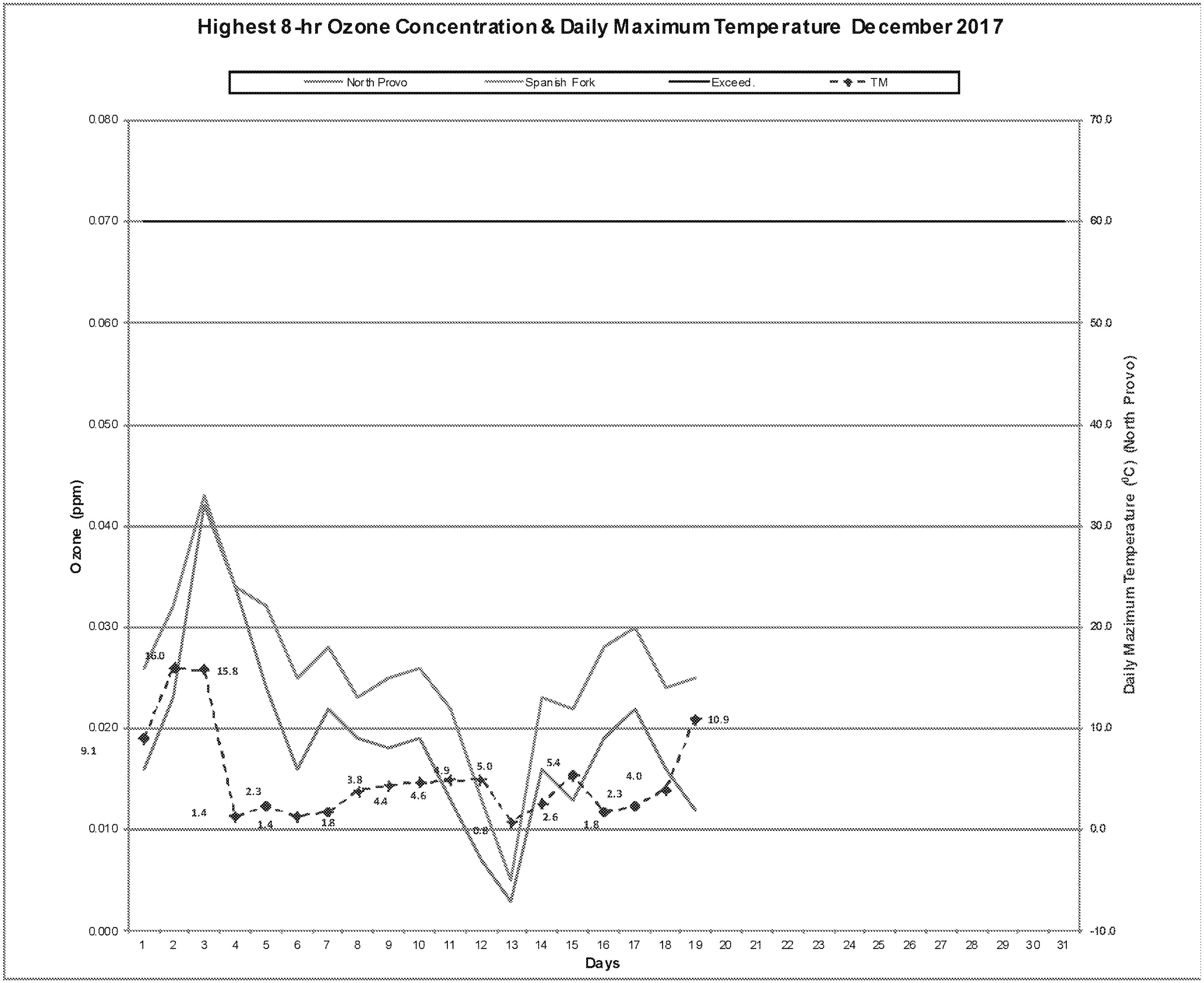


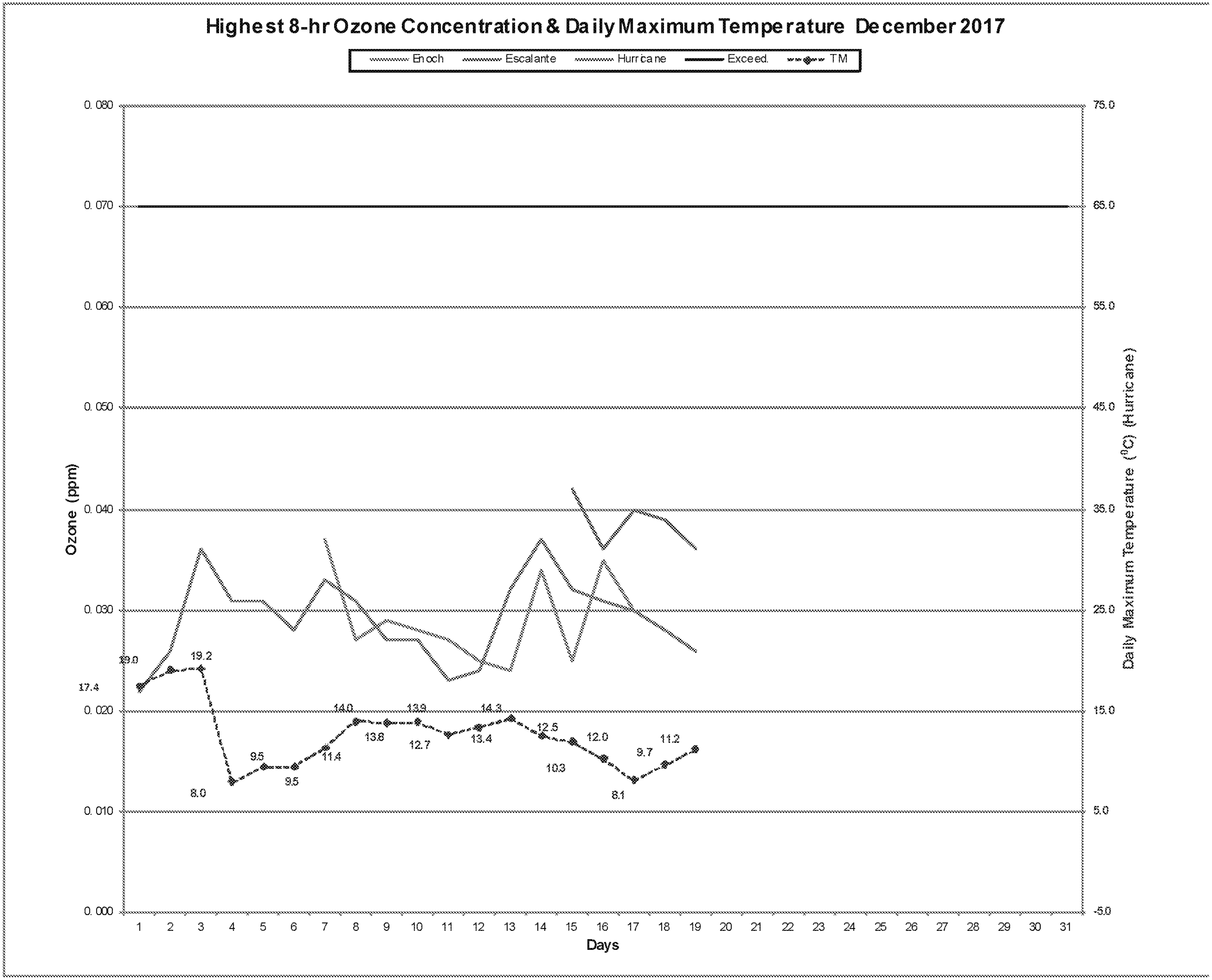
Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2017
Brigham City
Bountiful
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Rose Park
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hawthorne)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
10.7
17.0
11.0
1.4
2.4
3.4
1.9
4.7
5.1
-0.1
4.6
0.0
-0.1
5.0
2.3
7.0
3.0
7.0
10.7



Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2017
Price #2
Roosevelt
Vernal
Exceed.
TM
Ozone (ppm)
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Daily Maximum Temperature (ºC) (Roosevelt)
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
-20.0
Days
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
7.0 9.5 9.9 3.7 0.5 0.9 -0.9 2.1 3.0 2.3 3.1 4.7 1.7 4.0 2.7 3.4 3.8 2.1 3.5


Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2017
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Smithfield)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
-20.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
4.5
-0.5
11.5
-1.5
-5.9
-5.6
-6.3
-5.2
-7.0
-6.2
-7.0
-4.7
-1.2
-4.9
-0.6
-1.4
-2.2
0.0
2.3


Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2017
North Provo
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Mazimum Temperature (°C) (North Provo)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
-10.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
16.0
15.8
9.1
10.9
2.3
1.4
1.4
1.8
3.8
4.4
4.6
4.9
5.0
0.8
5.4
2.6
2.3
1.8
4.0



Highest 8-hr Ozone Concentration & Daily Maximum Temperature December 2017
Enoch
Escalante
Hurricane
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hurricane)
Days
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
75.0
65.0
55.0
45.0
35.0
25.0
15.0
5.0
-5.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
17.4
19.0
19.2
8.0
9.5
9.5
11.4
14.0
13.8
13.9
12.7
13.4
14.3
12.5
10.3
12.0
8.1
9.7
11.2